MILLENNIUM BULK TERMINALS—LONGVIEW SEPA ENVIRONMENTAL IMPACT STATEMENT

SEPA GREENHOUSE GAS EMISSIONS TECHNICAL REPORT

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Acronyms and Abbreviations

°F	degrees Fahrenheit
Applicant	Millennium Bulk Terminals—Longview, LLC
AR4	IPCC Fourth Assessment Report
BNSF	BNSF Railway Company
Btu	British thermal unit
Btu/lb	British thermal units per pound
CCC	Cowlitz County Code
CFR	Code of Federal Regulations
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
eGRID	Emissions & Generation Resource Integrated Database
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FR	*Federal Register*
GHG	greenhouse gas
GMI	Global Methane Initiative
GREET	Greenhouse gases, Regulated Emissions and Energy use in Transportation Model
GWP	global warming potential
hp	horsepower
IPCC	Intergovernmental Panel on Climate Change
$kgCO_2e$	kilograms of carbon dioxide equivalent
$kgCO_2e$/MWh	kilograms of carbon dioxide equivalent per megawatt hour
$kgCO_2e$/Mt	kilograms of carbon dioxide equivalent per metric ton
kWh	kilowatt hour
LVSW	Longview Switching Company
MJ	megajoule
MMBtu	million British thermal units
$MMTCO_2e$	million metric tons of carbon dioxide equivalent
MOVES	MOtor Vehicle Emission Simulator
$MtCO_2e$	metric tons of carbon dioxide equivalent
MWh	megawatt hour
NEPA	National Environmental Policy Act
RCW	Revised Code of Washington
SEPA	Washington State Environmental Policy Act
UNFCCC	United Nations Framework Convention on Climate Change
UP	Union Pacific Railway
USC	United States Code
WAC	Washington Administrative Code

Chapter 1
Introduction

This technical report assesses the potential greenhouse gas (GHG) emissions impacts of the proposed Millennium Bulk Terminals—Longview project (Proposed Action) and No-Action Alternative. For the purposes of this assessment, GHG emissions include the emissions from construction and operation of the Proposed Action as well as the indirect, market-influenced transportation, coal extraction, and end-use fossil fuel combustion emissions from operations. This report describes the regulatory setting, establishes the methods for assessing potential GHG emissions impacts, presents current GHG emissions in the study area, and assesses potential net GHG emissions from the Proposed Action and the No-Action Alternative.

1.1 Project Description

Millennium Bulk Terminals—Longview, LLC (Applicant) is proposing to construct and operate a coal export terminal (Proposed Action) in Cowlitz County, Washington, along the Columbia River (Figure 1). The coal export terminal would receive coal from the Powder River Basin in Montana and Wyoming and the Uinta Basin in Utah and Colorado via rail shipment. The coal export terminal would receive, stockpile, and load coal onto vessels and transport the coal via the Columbia River and Pacific Ocean to overseas markets in Asia.

1.1.1 Proposed Action

Under the Proposed Action, the Applicant would develop the coal export terminal on 190 acres (project area) primarily within an existing 540-acre site that is currently leased by the Applicant (Applicant's leased area). The project area is adjacent to the Columbia River in unincorporated Cowlitz County, Washington near Longview, Washington (Figure 2). The Applicant currently operates and would continue to operate a bulk product terminal within the Applicant's leased area.

BNSF Railway Company (BNSF) or Union Pacific Railroad (UP) trains would transport coal on BNSF main line routes in Washington State, and the BNSF Spur and Reynolds Lead in Cowlitz County to the project area. Coal would be unloaded from rail cars, stockpiled, and loaded by conveyor onto ocean-going vessels for export at two new docks (Docks 2 and 3) located in the Columbia River.

Once construction is complete, the Proposed Action could have a maximum annual throughput capacity of up to 44 million metric tons of coal per year. The coal export terminal would consist of one operating rail track, eight rail tracks for storing up to eight unit trains, rail car unloading facilities, a stockpile area for coal storage, conveyor and reclaiming facilities, two new docks in the Columbia River (Docks 2 and 3), and shiploading facilities on the two docks. Dredging of the Columbia River would be required to provide access to and from the Columbia River navigation channel and for berthing at the two new docks.

Vehicles would access the project area from Industrial Way (State Route 432), and vessels would access the project area via the Columbia River. The Reynolds Lead and BNSF Spur track—both jointly owned by BNSF and UP and operated by Longview Switching Company (LVSW)—provide rail access to the project area from a point on the BNSF main line (Longview Junction) located to the east in Kelso, Washington. Coal export terminal operations would occur 24 hours per day, 7 days per week. The coal export terminal would be designed for a minimum 30-year period of operation.

At full terminal operations, approximately 8 loaded unit trains each day would carry coal to the export terminal, 8 empty unit trains each day would leave the export terminal, and an average of 70 vessels per month or 840 vessels per year would be loaded, which would equate to 1,680 vessel transits in the Columbia River annually.

Figure 1. Project Vicinity

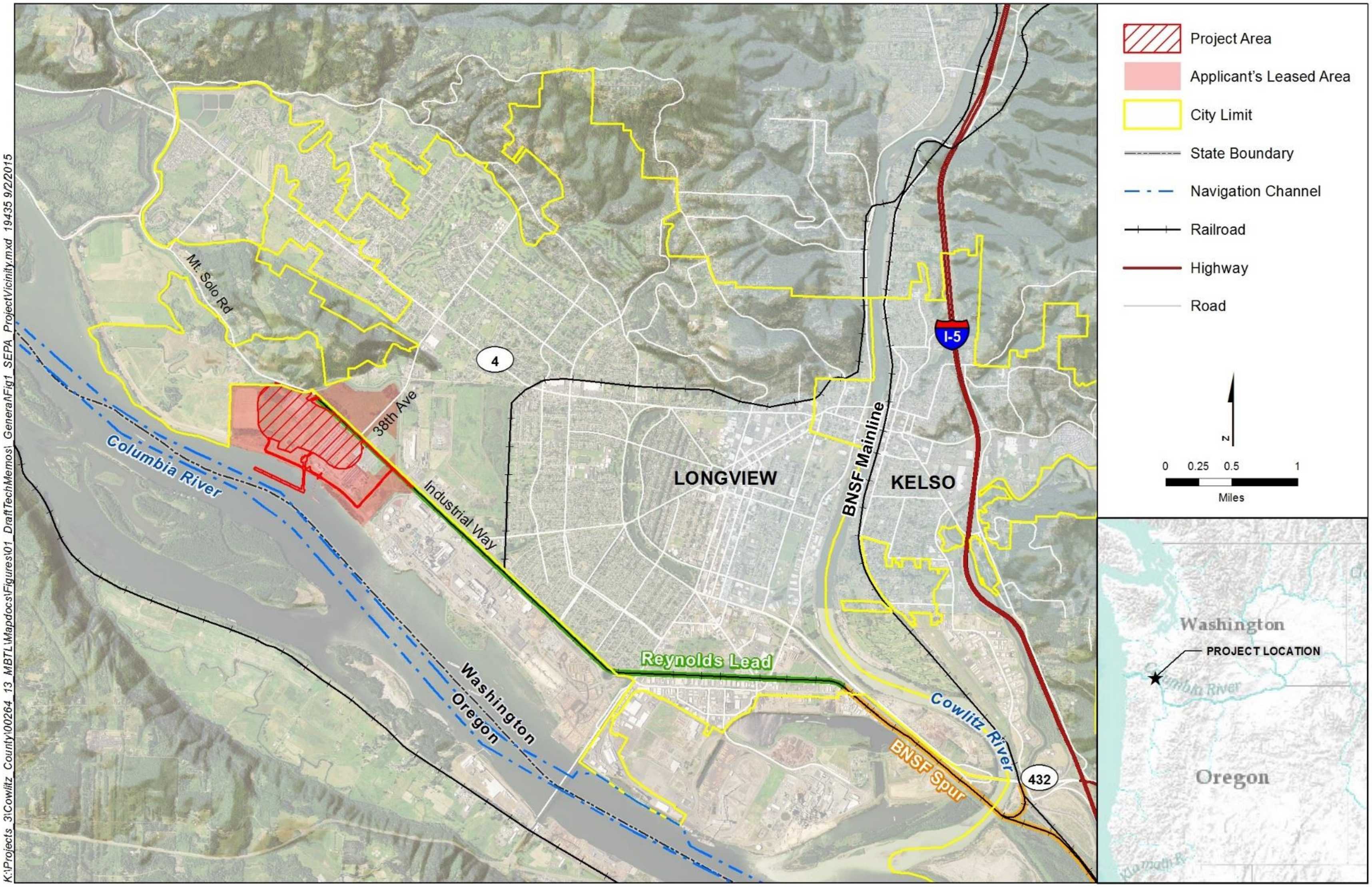
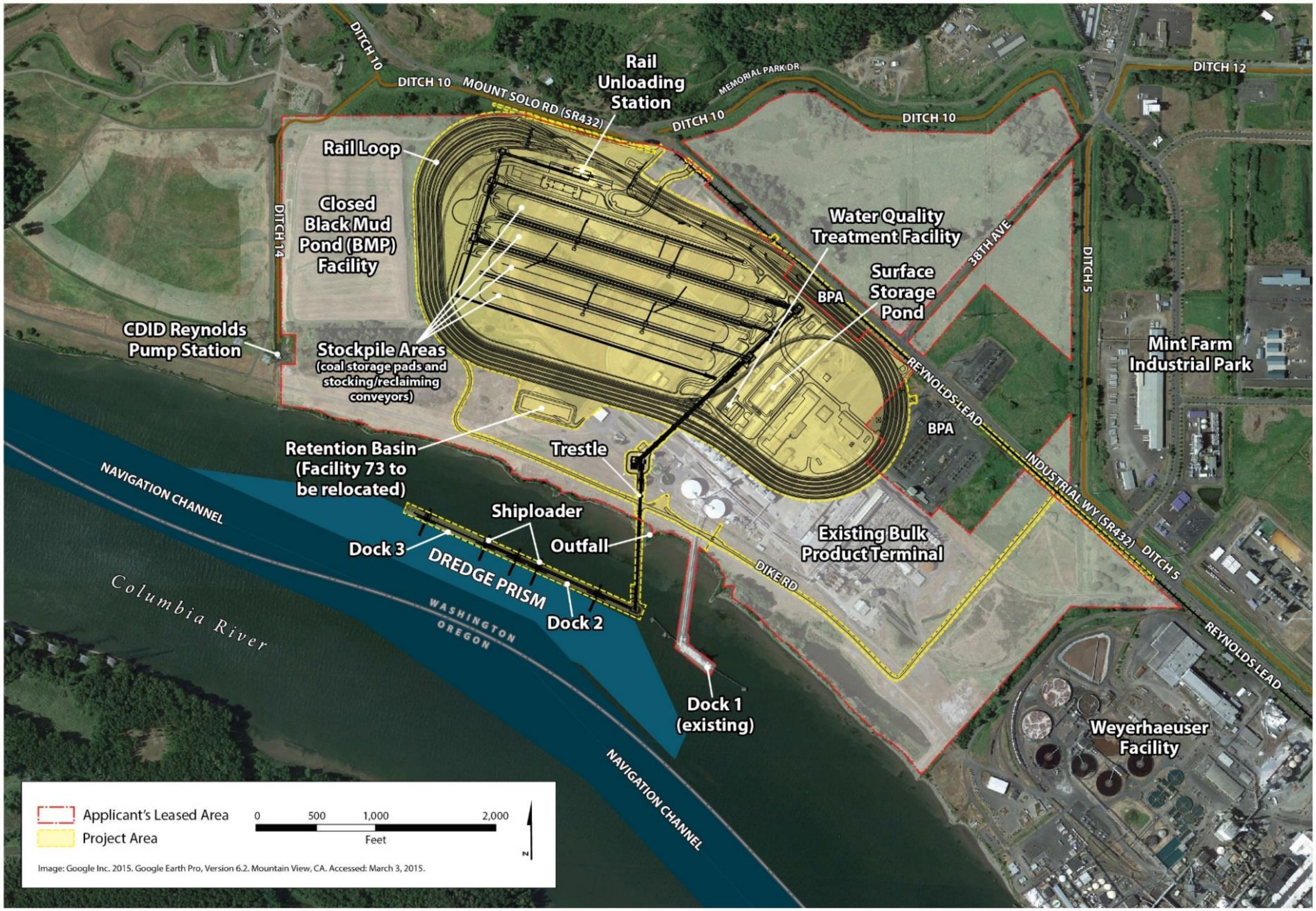


Figure 2. Proposed Action



1.1.2 No-Action Alternative

The Applicant plans to continue operating its existing bulk product terminal located adjacent to the project area. Ongoing operations would include storing and transporting alumina and small quantities of coal and continued use of Dock 1. Maintenance of the existing bulk product terminal would continue, including maintenance dredging at the existing dock every 2 to 3 years. The Applicant plans to expand operations at the existing bulk product terminal, which could include increased storage and upland transfer of bulk products utilizing new and existing buildings. The Applicant would likely need to undertake demolition, construction, and other related activities to develop expanded bulk product terminal facilities.

If the coal export terminal is not constructed, the Applicant would likely propose expansion of the bulk product terminal onto areas that would have been subject to construction and operation of the proposed coal export terminal. Additional bulk product transfer activities could involve products such as a calcined pet coke, coal tar pitch, cement, fly ash, and sand or gravel. Any new operations would be evaluated under applicable regulations. Upland areas of the project area are zoned Heavy Industrial and it is assumed future proposed industrial uses in these upland areas could be permitted. Any new construction would be limited to uses allowed under existing Cowlitz County development regulations.

1.2 Regulatory Setting

The jurisdictional authorities and corresponding regulations, statutes, and guidance for determining potential impacts on GHG emissions are summarized in Table 1.

Table 1. Regulations, Statutes, and Guidance for Greenhouse Gas Emissions

Regulation, Statute, Guideline	Description
Federal	
National Environmental Policy Act (42 USC 4321 *et seq*.)	Requires the consideration of potential environmental effects. NEPA implementation procedures are set forth in the President's Council on Environmental Quality Regulations for Implementing NEPA (49 CFR 1105).
Clean Air Act of 1963 (42 USC 7401) as amended	In 2007, the U.S. Supreme Court ruled that GHGs are air pollutants under the Clean Air Act.
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units	In 2015, under the Clean Power Plan, EPA set state-specific target emission reductions to reduce CO_2 emissions in the power sector by 32% below 2005 levels by 2030 (80 FR 64661). The rate-based CO_2 emission goal for Washington state is 983 pounds of CO_2 per net MWh (80 FR 64962) and the mass-based CO_2 emission goal for Washington state for the 2 year block of 2030–2031 is 21,478,344 short tons of CO_2 (80 FR 64963) (or a final goal of 10,739,172 short tons of CO_2 (80 FR 64825).
United States Submittal to the United Nations Framework on Climate Change	United States and other nations submitted Intended Nationally Determined Contribution to the United Nations in 2015.

Regulation, Statute, Guideline	Description
State	
Washington State Environmental Policy Act (WAC 197-11, RCW 43.21C)	Requires state and local agencies in Washington to identify potential environmental impacts that could result from governmental decisions.
Limiting Greenhouse Gas Emissions (RCW 70.235)	Requires state to reduce overall GHG emissions as compared to a 1990 baseline and report emissions to the governor bi-annually. Specific goals include achieving 1990 GHG emissions levels by 2020; 25% below 1990 levels by 2035; and 50% below 1990 levels by 2050 or 70% below the state's expected emissions that year.
Washington Clean Air Act (RCW 70.94)	Establishes rules regarding preservation of air quality and penalties for violations. CO_2 mitigation fees are evaluated as part of the permit required by the Clean Air Act (RCW 70.94.892) to reflect requirements from RCW 80.70. RCW 70.94.151 states that the department will be responsible for adopting rules requiring reporting of emissions defined by 70.235.010 from facility, source, site, or fossil fuel supplier that meet or exceed 10,000 metric tons of CO_2e annually.
Washington Carbon Pollution and Clean Energy Action (Executive Order 14-04, 2014)	In April 2014, Governor Inslee established the Governor's Carbon Emissions Reduction Taskforce to provide recommendations to the 2015 legislative session on the design and implementation of a carbon emissions limits and market mechanisms program for Washington State. The task force delivered its findings in November 2014, noting that a harmonized, comprehensive emissions-based or price-based policy approach would add unique features to an overall carbon emission reduction policy framework.
Washington Clean Air Rule (WAC 173-442)	Establishes requirements to cap and reduce GHG emissions. Parties covered under the Clean Air Rule are required to reduce their covered GHG emissions along an emission reduction pathway by reducing their emissions or by obtaining emission reductions from other covered parties, in-state emission reduction projects, or out-of-state emissions market (cap & trade) programs. The Clean Air Rule covers two-thirds of Washington's GHG emissions.
Washington's Leadership on Climate Change (Executive Order 09-05, 2009)	In 2009, Governor Gregoire ordered the state to assess the effectiveness of various GHG reduction strategies by estimating emissions, quantifying necessary reductions, and identifying strategies and actions that could be used to meet the 2020 target. Assessments were done across multiple sectors and sources of emissions, including industrial facilities, the electricity sector, low-carbon fuel standards, vehicle miles traveled, coal plants, and forestry.
Path to a Low-Carbon Economy: An Interim Plan to Address Washington's Greenhouse Gas Emissions (2010)	The second Climate Comprehensive Plan report to the Governor and State Legislature outlines a plan to achieve emission reductions to 1990 levels by 2020, as required by RCW 70.235.

Local	
Cowlitz County SEPA Regulations (CCC 19.11)	Provides for the implementation of SEPA in Cowlitz County.

Notes:

[a] In 2009, EPA proposed the Endangerment Finding and the Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act. The Endangerment Findings determined that the current and projected concentrations for carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorinated chemicals, and sulfur hexafluoride posed a threat to the health and welfare of current and future generations (U.S. Environmental Protection Agency 2009). This sets the legal foundation for regulating GHG emissions from sources of these six well-known GHGs, such as vehicles, industrial facilities, and power plants.

[b] Light duty vehicles include passenger cars, light-duty trucks, and medium-duty passenger vehicles.

USC = United States Code; CFR = Code of Federal Regulations; EPA = U.S. Environmental Protection Agency; FR = *Federal Register*; CO_2 = carbon dioxide; MWh = megawatt per hour; CO_2e = carbon dioxide equivalent; GHG = greenhouse gas; WAC = Washington Administrative Code; RCW = Revised Code of Washington; SEPA = Washington State Environmental Policy Act; CCC = Cowlitz County Code

1.3 Study Area

GHG emissions contribute to the global greenhouse effect, which is the process by which the Earth retains heat (Section 2.1, *Greenhouse Effect*). GHGs emitted anywhere in the globe affect the global environment.[1] The study area for GHG emissions for Cowlitz County as a Washington State Environmental Policy Act (SEPA) co-lead agency is defined as Cowlitz County. GHG emissions for the Washington State Department of Ecology as a SEPA co-lead agency is based on the expected rail and vessel transportation routes and emissions from the combustion of coal. While the study areas for the co-lead agencies are different, the analysis used the same approach to calculate GHG emissions attributable to the Proposed Action.

[1] Some short-lived climate pollutants, such as black carbon, have only a local impact and are not considered in this analysis.

Chapter 2
Existing Conditions

This chapter introduces the greenhouse effect, which is the primary consequence of GHG emissions. The chapter then describes the sources of information and methods used to characterize the existing conditions and assess the potential impacts of the Proposed Action.

2.1 Greenhouse Effect

The Earth retains outgoing thermal energy and incoming solar energy in the atmosphere, thus maintaining heat temperature levels suitable for biological life. This retention of energy by the atmosphere is known as the greenhouse effect.[2] When solar radiation reaches the Earth, most of the solar radiation is absorbed by the Earth's surface, reflected by the Earth's surface and atmosphere, or — to a lesser degree — absorbed by the Earth's atmosphere. Simultaneously, the Earth radiates its own heat and energy out into the Earth's atmosphere and space. Factors such as the reflectivity of the Earth's surface, the abundance of water vapor, or the extent of cloud cover affects the degree to which solar radiation may be absorbed and reflected. Figure 3 shows the energy flows to and from Earth and the role that the greenhouse effect plays in maintaining heat in the atmosphere.

The composition of gases in the Earth's atmosphere determines the amount of energy absorbed and re-emitted by the atmosphere or simply reflected back into space. The predominant gases in the Earth's atmosphere, nitrogen and oxygen (which together account for nearly 90% of the atmosphere) exert little to no greenhouse effect. Some naturally occurring gases, such as carbon dioxide (CO_2), methane, and nitrous oxide, trap outgoing energy and contribute to the greenhouse effect. Additionally, manufactured pollutants, such as hydrofluorocarbons, can contribute to the greenhouse effect. Unlike most air pollutants (e.g., sulfur dioxide and particulate matter) that have only a local impact on air quality, GHGs affect the atmosphere equally regardless of where they are emitted, and thus they are truly global pollutants. Therefore, a ton of CO_2 emissions in Asia affects the global atmosphere to the same degree as a ton of CO_2 emissions in the United States.

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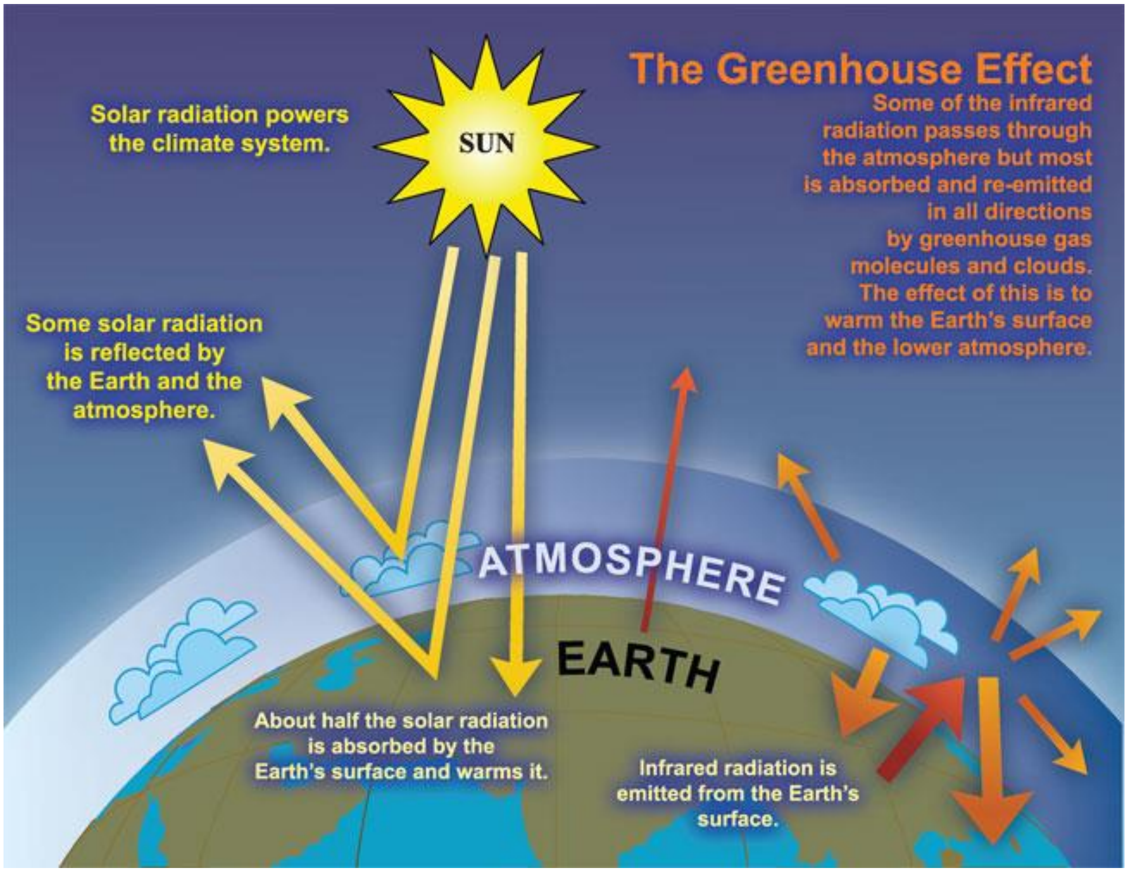
[2] The Intergovernmental Panel on Climate Change (2013) defines the greenhouse effect as follows:

The infrared radiative effect of all infrared-absorbing constituents in the atmosphere. Greenhouse gases (GHGs), clouds, and (to a small extent) aerosols absorb terrestrial radiation emitted by the Earth's surface and elsewhere in the atmosphere. These substances emit infrared radiation in all directions, but, everything else being equal, the net amount emitted to space is normally less than would have been emitted in the absence of these absorbers because of the decline of temperature with altitude in the troposphere and the consequent weakening of emission. An increase in the concentration of GHGs increases the magnitude of this effect; the difference is sometimes called the enhanced greenhouse effect. The change in a GHG concentration because of anthropogenic emissions contributes to an instantaneous radiative forcing. Surface temperature and troposphere warm in response to this forcing, gradually restoring the radiative balance at the top of the atmosphere.

Figure 3. Model of the Natural Greenhouse Effect



Source: Intergovernmental Panel on Climate Change 2007

The extent to which a given GHG traps energy in the atmosphere and contributes to the overall greenhouse effect is characterized by its global warming potential (GWP). Some gases are more effective at trapping heat, while others may be longer-lived in the atmosphere. The reference gas against which others are compared is carbon dioxide, and GWP is thus expressed in terms of carbon dioxide-equivalent (CO_2e). The unit CO_2e represents both a gas's ability to trap heat and the rate at which it breaks down in the atmosphere. Most analyses use 100 years as the period of reference for GWPs, and this technical report conforms to that convention. For example, 1 unit of carbon dioxide has a 100-year GWP of 1, whereas an equivalent amount of methane has a GWP of 25 (Intergovernmental Panel on Climate Change 2007). For this analysis, a 100-year period is used.

Table 2 presents the 100-year GWPs from the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) for the GHGs included in the study.[3,4]

Table 2. Global Warming Potentials

Greenhouse Gas	IPCC AR4 100-Year Global Warming Potential
Carbon dioxide	1
Methane	25
Nitrous oxide	298

Source: Intergovernmental Panel on Climate Change 2007

GHG emissions occur from both natural as well as human-made (anthropogenic) sources. Examples of natural sources include decomposition of organic matter and aerobic respiration. Anthropogenic GHG emissions are predominantly from the combustion of fossil fuels, although other sources including industrial processes, land-use change, agriculture, and waste management are also contributors.

The increase of GHGs in the atmosphere has been determined to pose risks to human and natural systems (Intergovernmental Panel on Climate Change 2014). Atmospheric concentrations of GHGs have increased since the Industrial Revolution, but the natural processes that remove those GHGs from the atmosphere have not scaled proportionally. Additionally, concentrations of long-lived manufactured pollutants such as hydrofluorocarbons have increased in recent decades. As the atmospheric concentrations of GHGs increase, the atmosphere's ability to retain heat increases as well. Since the instrumental record began in 1895, the U.S. average temperature has risen by approximately 1.3 to 1.9 degrees Fahrenheit (°F) (U.S. Global Change Research Program 2014). Furthermore, U.S. average temperatures throughout the 21st century are expected to increase at a faster pace, by 2.5°F to 11°F above pre-industrial levels by 2100 (U.S. Global Change Research Program 2014).

The impacts of higher global surface temperatures include widespread changes in the Earth's climate system. This may affect weather patterns, biodiversity, human health, and infrastructure. A discussion of climate impacts as they relate to the Proposed Action is provided in the SEPA Climate Change Technical Report (ICF 2017a)

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[3] While additional GHGs (HFCs, PFCs, SF_6) were considered for this analysis as per the Council on Environmental Quality (2016) guidance, carbon dioxide, methane, and nitrous oxide are the greenhouse gases emitted from the fossil fuel combustion and vegetation and wetland activities considered in the analysis.

[4] GWP values for methane have been revised over time from 21 in the IPCC Second Assessment Report (SAR) to 28 in the IPCC Fifth Assessment Report (AR5). GWP values for nitrous oxide have also been revised from 310 in the IPCC SAR report to 265 in the IPCC AR5 report (Intergovernmental Panel on Climate Change 2013; Intergovernmental Panel on Climate Change 1995). This range shows there is uncertainty associated with GWP values. The GWP values used for this report were selected to be consistent with standards developed for the U.S. GHG inventory. The United States and other developed countries of the UNFCCC have agreed to submit annual inventories in 2016, and future years to the UNFCCC using the 100-year GWP values from the IPCC AR4 report. EPA follows this guidance in generating the national greenhouse gas inventory (U.S. Environmental Protection Agency 2016b). Using the AR4 100-year GWPs in the EIS is consistent with the practice of the UNFCCC, and provides greenhouse gas data that are consistent with other corporate, national, and subnational reporting.

2.2 Methods

This section presents the data sources and methods used to estimate project related GHG emissions for the study area. First, the data sources that were used are summarized. Second, the methods used to estimate each source of GHG emissions are described.

2.2.1 Data Sources

The technical reports supporting the SEPA Draft Environmental Impact Statement (EIS) for the Millennium Bulk Terminals—Longview project provided activity data and emissions data to support the GHG analysis. The following sources of information were used to evaluate the GHG emissions from construction and operation of the Proposed Action, the combustion of coal from coal exported from the Proposed Action, domestic and international transport of the coal, and changes in the use of coal and natural gas in response to the operation of the Proposed Action.

- SEPA Air Quality Technical Report (ICF 2017b).
- SEPA Coal Market Assessment Technical Report (ICF 2017c).[5]
- SEPA Energy and Natural Resources Technical Report (ICF 2017d).
- SEPA Rail Transportation Technical Report (ICF and Hellerworx 2017).
- SEPA Vessel Transportation Technical Report (ICF 2017e).
- SEPA Vegetation Technical Report (ICF 2017f).
- SEPA Vehicle Transportation Technical Report (ICF and DKS Associates 2017).

To estimate the GHGs emitted as a result of the processes described in the above reports, ICF used those reports' estimates of fuel consumption and vehicle operation, referred to as activity data, and combined that data with GHG emission factors in order to estimate GHG emissions for the Proposed Action.[6] The GHG emission factors are drawn from the following sources.

- California Air Resources Board. 2011. Appendix D: Emissions Estimation Methodology for Ocean-Going Vessels.
- Clean Cargo Working Group, 2014. Global Maritime Trade Lane Emissions Factors.
- Energy Information Agency 1994. CO_2 Emission Factors for Coal Study for International Coals.
- Hansen 2009. The Viability of Creating Wetlands for the Sale of Carbon Offsets.
- Intergovernmental Panel on Climate Change 2006: Volume 4: Agriculture, Forestry, and Other Land Use.

[5] The SEPA Coal Market Assessment Technical Report (ICF 2017c), hereafter referred to as the coal market assessment, provides estimates on the net changes in international coal extraction and combustion, domestic substitution of natural gas for coal and resulting combustion, extraction of coal at U.S. coal mines, domestic transport of coal to the proposed project, and international transport of the coal to importing countries. The report provides estimates for several scenarios to cover a range of potential changes in net GHG emissions because of the Proposed Action.

[6] An activity is a practice or ensemble of practices that take place on a delineated area over a given period. Activity data are data on the magnitude of a human activity resulting in emissions or removals taking place during a given period of time (e.g., data on energy use, data on equipment used during construction of the Proposed Action) (Intergovernmental Panel on Climate Change 2006).

- Coal Mine Methane Country Profiles (Global Methane Initiative 2015).
- International Energy Statistics (Energy Information Agency 2017).
- IPCC Guidelines for National Greenhouse Gas Inventories (Intergovernmental Panel on Climate Change 2006).
- National Council for Air and Stream Improvement and U.S. Forest Service 2016. Carbon Online Estimator.
- Trettin and Jurgensen 2003. Carbon Cycling in Wetland Forest Soils.
- U.S. Environmental Protection Agency. 1996. AP-42, Section 3.4 Large Stationary Diesel and All Stationary Dual-fuel Engines.
- U.S. Environmental Protection Agency. 2009a. NONROAD Model (Non-road engines, equipment, and vehicles).
- U.S. Environmental Protection Agency. 2009b. Emission Factors for Locomotives.
- U.S. Environmental Protection Agency. 2014a. MOVES (Motor Vehicle Emission Simulator).
- U.S. Environmental Protection Agency. 2015c. U.S. Greenhouse Gas Inventory Report: 1990–2013.
- U.S. Greenhouse Gas Inventory Report: 1990–2014 (U.S. Environmental Protection Agency 2016b).

2.2.2 Impact Analysis

This section describes the methods used to evaluate the potential impacts of the Proposed Action on GHG emissions. The method for estimating the GHG emissions associated with each emission source is described, along with that source's activity data and the calculations used to estimate its associated GHG emissions. The GHG analysis addresses the same set of sources addressed in the SEPA Air Quality Technical Report (ICF 2017b), plus several additional sources (e.g., transportation emissions beyond a 5-mile radius, net emissions from changes in domestic and international coal use).

2.2.2.1 Scope of Analysis

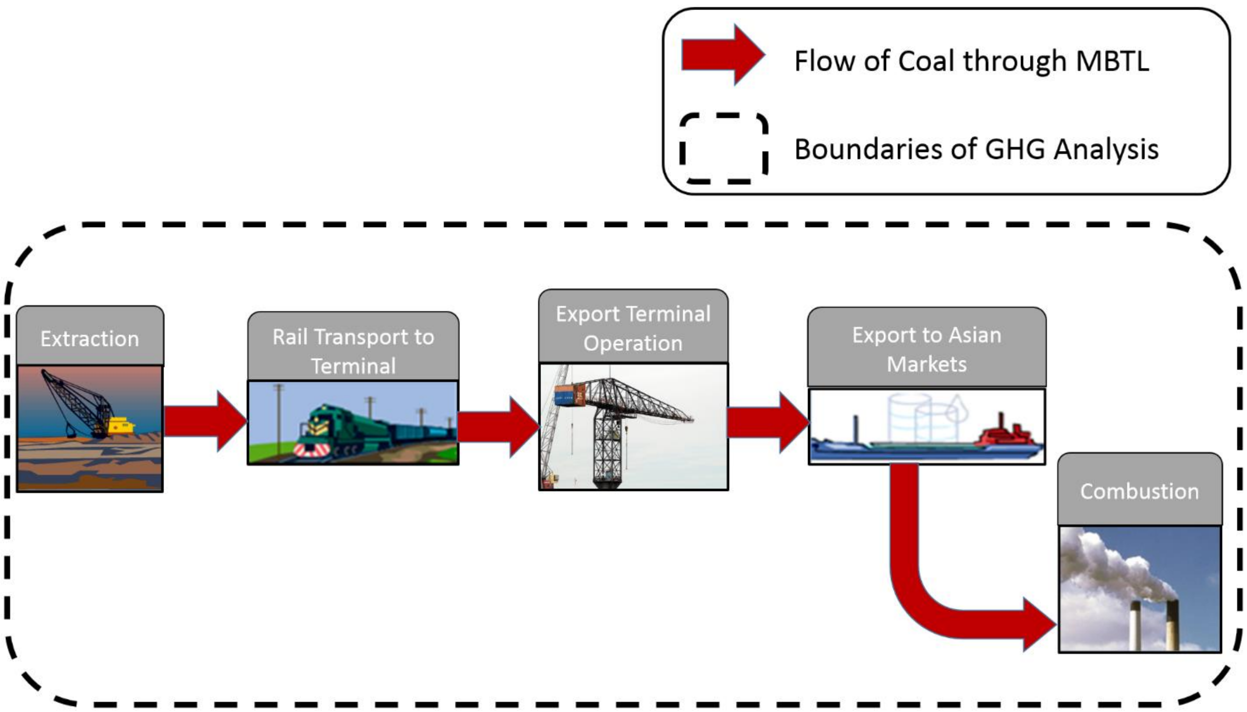
The Proposed Action would emit GHGs during construction and operation, both in the United States and abroad. The emissions would come predominantly from the combustion of fossil fuels for construction and operation, as well as changes in the combustion of coal, both domestically and internationally.

This analysis includes activity data from the technical reports described in Section 2.2.1, *Data Sources.* Additionally, the GHG analysis evaluates emissions scenarios based on the ultimate flow of coal to and through the coal export terminal (ICF 2017c). Figure 4 shows the pathway of coal from extraction to transport to terminal operation to export to its final combustion.

Geographically, the analysis of GHG emissions from the Proposed Action includes the extraction of Powder River Basin and Uinta Basin coals, the rail transport of the coal to Cowlitz County from their points of extraction, coal export terminal operation in Cowlitz County, vessel transport to Asia, and the substitution of coal for end-use combustion in China, Hong Kong, Japan, South Korea, and

Taiwan. Changes in coal combustion elsewhere in Asia (e.g., India) are included in this analysis where coal use would be affected by the import of coal from the coal export terminal (i.e., by induced demand for coal and substitution of international coals for U.S.-based coals). The substitution of natural gas for coal in the United States because of an increase in domestic coal prices is also evaluated.[7]

Figure 4. Coal Export Stages and GHG Analysis Boundaries



The scope of the GHG emissions analysis considers the following elements.

- **Analysis period.** To be consistent with activity data from the other technical reports prepared for the Proposed Action, this analysis considers construction, operation, coal extraction, rail and vessel transport, and fossil fuel combustion emissions from 2018 through 2038.
- **Direct sources of GHG emissions.** Direct emissions refer to GHG emissions from coal export terminal construction, operation, and transportation within Cowlitz County. The following processes are included.
    - Upland and wetland land-cover change
    - Coal export terminal construction
    - Dock dredging during coal export terminal construction and operations and subsequent release of sediment carbon
    - Rail transport of coal in Cowlitz County
    - Vehicle-crossing delay in Cowlitz County

[7] The proposed coal terminal could increase the demand for U.S. coal, resulting in a corresponding increase in coal prices.

 - Equipment use during coal export terminal operation
 - Vessel idling and tugboat use at the coal export terminal
 - Vessel transport of coal in Cowlitz County
 - Employee commuting to and from the coal export terminal

- **Indirect sources of GHG emissions.** Indirect emissions refer to GHG emissions that would result from the Proposed Action but are not concurrent with construction or operation on the project area, or that would occur outside of Cowlitz County. The following are indirect sources of GHG emissions.
  - Coal export terminal construction—embedded GHG emissions in materials for coal export terminal construction
  - Extraction of coal at the mining sites
  - Rail transport of coal from extraction sites to Washington State
  - Rail transport of coal within Washington State
  - Consumption of electricity used for coal export terminal operations
  - Helicopter and pilot boat trips for pilot transfers to vessels
  - Vessel transport of coal between the Cowlitz County border and international waters and return of vessels with only ballast water
  - Vessel transport of coal in international waters to markets in China, Hong Kong, Japan, South Korea, and Taiwan and return of vessels with only ballast water
  - Market effects on coal combustion in Asia and the United States
  - Induced natural gas combustion in the United States
- **Geographic scope.** The geographic scope includes GHG emissions that would occur within and outside of the project area. Emissions are evaluated outside of the area because greenhouse gases are a global pollutant as stated in Section 2.1, *Greenhouse Effect*, and there are market impacts from the Proposed Action at multiple geographic scales resulting in GHG emissions. Direct emissions that occur on the project area include those from mobile sources during construction and operation. Additional direct emissions would occur in Cowlitz County from rail and vessel transport of coal. The following indirect emissions would occur.
  - Rail and vessel transport of the coal beyond Cowlitz County and within Washington State
  - Net extraction of the coal in the United States and international coal markets
  - Rail transport of coal from extraction sites to Washington State
  - Transport of coal to Asian markets and the return of vessels with only ballast water in international waters

  GHG emissions are also estimated that would result from shifts in coal combustion and demand in Asian markets and from induced natural gas combustion due to the shift from coal as coal prices increase (relative to the no-action as defined in the coal market assessment) in the United States.

The international coal market is a global commodity market, such that changes in supply or demand in one country can affect coal prices and distribution patterns globally. The global nature of the coal market was demonstrated most recently in the fall of 2016 when China reduced production capacity and international coal prices shot up by 50% over a 2-month period. In addition, coal competes with other fuel sources, such as natural gas, for electric generation. To capture the dynamic changes in the international coal market and the competition among fuel types for electric generation in the United States and Canada, a comprehensive and integrated modeling platform is required. Without this type of modeling, assumptions would be required regarding the ultimate outcome of the exported coal and changes in coal consumption in the United States that would be difficult to make and justify without comprehensive modeling. The importance of modeling is best illustrated by examples.

- The model established that there are very large existing international coal markets, and there is at most a relatively small increase in coal consumption because of the introduction of a new coal supply.
- The model established that there are multiple suppliers and that, while U.S. exports are competitive, they are not significantly lower in cost than coal supplied from Australia, China, Indonesia, or Russia. The model showed outcomes where displacement—i.e., sale of U.S. coal rather than sale of competing coal produced in other countries—resulted in small changes in delivered coal price and small to no increases in coal used, except in the Upper Bound Scenario.
- The model established that the variation in coal emission rates had limited effects on total emissions, although differences in carbon content have somewhat greater effect on net emissions from the Proposed Action. Thus, depending on the scenario, the substitution of coal with different carbon contents in Asia can be one of the key drivers of net emissions compared to other sources such as international vessel transport.
- The U.S. power and fuel markets are highly integrated, diverse, and competitive, and, consequently, the increase in coal price in the United States results in substitution of gas and other sources for coal.

- **Induced demand for energy.** This analysis addresses coal combustion in Asia that would result from the increased supply of coal due to the operation of the Proposed Action. The addition of 44 million metric tons of coal to the supply of coal in Asia would increase supply and lower international coal prices. Asian coal markets would respond to lower prices by consuming more coal overall. This additional demand for coal that is a result of shifts due to the shift in the price of coal is referred to as induced demand.
- **Offset energy sources.** Operation of the Proposed Action could offset demand for other energy sources, nationally and internationally. Depending on the scenario, operations could affect production of coal from Australia, China, Indonesia, and Russia and its consumption throughout Asia. Additionally, this analysis considers the increased use of U.S. natural gas as a substitute for coal combustion. Consequently, changes in GHG emissions are estimated assuming that coal shipped through the coal export terminal would replace other sources of coal (e.g., coal imported from Australia, China, Indonesia, and Russia) and for the substitution of natural gas for U.S. coal. The GHG emissions associated with replacement of other sources of coal would include differences in the extraction and combustion of these coals compared to U.S. coal from Powder River and Uinta Basins.

- **Coal market assessment scenarios.** Each coal market assessment scenario represents a range of GHG emissions estimates, based on economic and policy projections through 2040. For each scenario, the GHG emissions from Asian coal combustion, U.S. coal combustion, and U.S. natural gas combustion are influenced by factors such as coal prices, transportation costs, demand for thermal coal, status of U.S. and international climate policies, and competing energy sources. Estimates of coal transport, coal consumption, and natural gas substitution are informed by projections in the coal market assessment, which considers four scenarios based on economic and policy projections through 2040.[8] The scenarios represent a range of GHG emissions estimates determined using a multi-dimensional model. Two model runs were conducted for each scenario: a no action model and an action model with the Proposed Action. The resulting net GHG emissions are influenced by the relative differences in coal combustion, distribution, and substitution for each of these model runs.

  The coal market assessment kept the throughput of exported coal constant at 44 million metric tons for the 6 years modeled (2016, 2018, 2020, 2025, 2030, and 2040) for the Proposed Action.[9] However, for the GHG analysis and as described in Section 2.2.2.2, *Method for Assembling an Emissions Time Series,* only years 2025, 2030, and 2040 from the coal market assessment results are used and adjusted to account for changes in quantities of exported coal from 2021 to 2028, the period when the coal export terminal would ramp up operations to reach full capacity in 2028.[10]

  All four scenarios use a common set of base assumptions, many of which were updated between the Draft EIS and Final EIS. Detailed descriptions of these assumptions are included in the coal market assessment. The set of base assumptions include, but are not limited to, the following. Assumptions.

  - Coal supply curves for U.S. and international coal supply regions. In the No Clean Power Plan scenario, the base coal supply curves result in Powder River Basin Wyoming 8800 British thermal units per pound (Btu/lb) of coal being priced at $12.6/ short ton, Uinta Basin 11,280 Btu/lb coal being priced at $39/ short ton, and Australian 10,800 Btu/lb (6,000 kilocalories per kilogram) coal being priced at $62.8/ short ton.[11] All prices are in 2012$ for the year 2018.
  - Coal transportation costs. The base rail transportation costs are $30 to $36 per short ton for coal transported from the Powder River Basin and Uinta Basin to the proposed terminal.
  - Natural gas supply curves
  - Air, waste, and water regulations
  - Renewable energy standards and regulations

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[8] In some other studies, scenarios of economic and policy conditions are compared against a common baseline. For this GHG Analysis, the baseline is redefined for each scenario. This approach is used to capture the range of economic and policy conditions that could exist in the future (i.e., 2025, 2030, and 2040).

[9] As described in the coal market assessment, 44 million metric tons of coal is modeled for each year rather than a gradual increase as the coal export terminal reached full capacity.

[10] For purposes of the GHG analysis, the effect of the Proposed Action on net GHG emissions starts in 2021 when the proposed terminal initiates operations, and therefore net GHG emissions from emission sources affected by the coal market assessment are assumed to be 0 $MMTCO_2e$ for 2016, 2018, and 2020. See Section 6.1 of the *SEPA Coal Market Assessment Technical Report* (ICF 2017c) for further information.

[11] British thermal units (Btu) are a standardized measurement of the heat content of coal.

- Reserve margin targets for each U.S. electric demand region
- Firmly planned new generating capacity and retirements
- Electric transmission limits
- Electric demand
- Capital costs for new electric-generating capacity
- International coal demand. The base assumption for international coal demand is the Current Policies scenario from the International Energy Agency's 2015 World Energy Outlook. The Current Policies scenario includes only those GHG reduction policies for which implementing measures have been formally adopted as of mid-2015, and assumes that these policies remain unchanged going forward.
- Elasticity of coal demand for the Asian countries that can receive coal from the proposed terminal. The base elasticity of coal demand for China is -0.44 and is -0.11 for Hong Kong, India, Japan, South Korea, and Taiwan.

The four scenarios incorporate the base assumptions and are differentiated by the following six parameters:

- International coal curves
- International coal demand
- Coal demand elasticity
- Powder River Basin and Uinta Basin coal curves
- U.S. rail transportation costs
- U.S. and international climate policy. The U.S. climate policy is incorporated into the modeling by using an assumed version of the Clean Power Plan, or by not including the Clean Power Plan.[12] The international climate policies are incorporated into the modeling through the international coal demand used in each scenario.

The four scenarios and their key concepts are described below and summarized in Table 3.

- **2015 U.S. and International Energy Policy Scenario.** The 2015 U.S. and International Energy Policy scenario includes U.S. and international climate policies as the defining feature of this scenario. The U.S. climate policy is modeled using a representation of the Clean Power Plan. The international climate policy is modeled by using the international coal demand in the International Energy Agency's 2015 World Energy Outlook New Policies scenario.[13] The 2015 U.S. and International Energy Policy scenario uses the base set of assumptions except for three parameters. First, the international thermal coal demand is taken from the World Energy Outlook demand forecast for the New Policies scenario,

[12] Because implementation of the Clean Power Plan will occur at the state level and states have not determined how they will implement the Clean Power Plan, a version of the Clean Power Plan consistent with one of the alternatives under the EPA's proposed Federal Plan for the Clean Power Plan that features state specific mass standards for existing units is used.

[13] The 2015 World Energy Outlook New Policies Scenario incorporates the policies and measures that affect energy markets that had been adopted by non-U.S. countries as of mid-2015 and other relevant intentions that have been announced, even when the precise implementing measures have not been fully defined.

because it represents coal demand under current and proposed GHG reduction policies. Second, the elasticity of coal demand for China is -0.32. Third, this scenario includes the Clean Power Plan, which reduces coal consumption in the United States (U.S. Environmental Protection Agency 2015b). The final Clean Power Plan was released in August 2015.[14]

- **No Clean Power Plan Scenario.** The No Clean Power Plan scenario represents the state of the energy markets as of 2016. However, it does not include implementation of the Clean Power Plan. The No Clean Power Plan scenario uses the base set of assumptions and assumes that no additional national or international climate policies will be enacted beyond those implemented by mid- 2015.

- **Lower Bound Scenario.** Due to uncertainty over future coal consumption trends, the coal market assessment constructed the Upper and Lower Bound scenarios in a way that they produce illustrative results for a broad range of outcomes. The Lower Bound scenario represents a plausible low estimate of global CO_2 emissions from coal combustion. This scenario is designed to be a plausible and reasonable lower bound of global CO_2 emissions and does not attempt to model an absolute lowest bound of CO_2 emissions. The energy markets under the Lower Bound scenario could reflect a large component of renewable energy resulting in reduced demand for coal combustion. To achieve the low estimate of global CO_2 emissions from coal combustion, the Lower Bound scenario adjusts all six of the parameters used to define the scenarios beyond the base set of assumptions.

  First, the international coal supply curves are decreased by 10% to reduce the likelihood of induced demand. Second, international coal demand is assumed to be as estimated in the International Energy Agency's 2015 World Energy Outlook New Policies scenario, as this scenario includes both existing and proposed GHG reduction policies, which result in less coal consumption. Third, the coal demand elasticity is assumed to be -0.32, which would result in less induced demand than in the other scenarios, except the Energy Policy scenario, which uses the same value. Fourth, Powder River Basin coal supply curves are increased by 25% to reflect higher than expected stripping ratios and that would result in lower coal consumption. Fifth, U.S. rail costs are increased by 20% to reflect higher than expected diesel fuel prices, which would tend to decrease coal consumption in favor of other generation. Sixth, the Lower Bound scenario assumes the Clean Power Plan is implemented in the United States and that proposed international GHG reduction policies are implemented, which are the same assumptions as used in the 2015 U.S. and International Energy Policy scenario.

[14] On August 3, 2015, EPA released the final Clean Power Plan, which regulates CO_2 emissions from existing fossil fuel generation sources under Section 111(d) of the Clean Air Act. "Existing" refers to units that commenced construction before January 8, 2014. EPA estimates that the plan will reduce power sector CO_2 emissions 32% below 2005 levels in 2030. States have flexibility to implement the program as a rate credit trading program or a mass allowance trading program. The plan specified initial state plans due September 2016, updated plans by September 2017, and final state plans by September 2018, with the initial implementation date set for 2022. In February 2016, the Supreme Court granted petitioners a stay of the Clean Power Plan. The stay will not be lifted until all court proceedings, potentially including a hearing by the Supreme Court of the full case, have been settled. The D.C. Circuit heard arguments in the case in September 2016. In March 2017, an Executive Order was issued to review the Clean Power Plan.

- **Upper Bound Scenario.** The Upper Bound scenario represents a reasonable upper bound estimate of global CO_2 emissions from coal combustion and uses assumptions that could maximize the amount of induced demand from the Proposed Action. International coal plant construction and thus coal demand is assumed higher than in all the other scenarios. This higher demand causes both international coal consumption and prices to increase. This scenario does not attempt to model an absolute upper bound of global CO_2 emissions or CO_2 emissions that would result from the Proposed Action.[15] To achieve the high estimate of global CO_2 emissions from coal combustion, the Upper Bound scenario adjusts all six of the parameters used to define the scenarios beyond the base set of assumptions.

  First, the international coal supply curves are increased by 50% to reflect the higher international demand and increase the likelihood of induced demand. Second, international coal demand is assumed to be higher than all the other scenarios due to increased development of coal-fired generating assets. The international coal demand is estimated by assuming the historical coal consumption growth rates for each country during the 2000 to 2012 period, which was a time when coal consumption was increasing rapidly. Third, the coal demand elasticity is assumed to be -0.68, which would result in more induced demand than in the other scenarios. Fourth, Powder River Basin coal supply curves are decreased by 15% to reflect lower than expected stripping ratios and that would result in higher coal consumption. Fifth, U.S. rail costs are decreased by 20% to reflect lower than expected diesel fuel prices, which would tend to increase coal consumption. Sixth, the Upper Bound scenario does not assume the Clean Power Plan is implemented in the United States and assumes that the increased coal consumption does not violate existing international GHG reduction policies.

Table 3 summarizes the scenarios modeled for the coal market assessment, including the cumulative scenario.[16] Many factors would affect the future export and consumption of coal for the Proposed Action. Consequently, the scenarios reflect a range of potential outcomes. For each scenario, the table provides the following information.

- **Purpose:** the phenomena that the scenario is intended to represent.
- **U.S. coal markets:** the domestic coal market reaction to changes in supply and pricing.
- **Asian coal markets:** the international coal market reaction to changes in supply and pricing.
- **Coal prices:** the increases and decreases in coal production and transportation costs relative to the No Clean Power Plan scenario. Coal prices are modeled relative to the No Clean Power Plan scenario rather than the other scenarios because it uses the base set of assumptions without modifications.
- **Climate policy:** Two scenarios (2015 U.S. and International Energy Policy and Lower Bound scenarios) capture the effect of the Proposed Action when the Clean Power Plan and international GHG reduction commitments are implemented.

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[15] Due to uncertainty over future coal consumption trends, the coal market assessment constructed the Upper and Lower Bound scenarios to illustrate a broad range of outcomes but not the extreme possibilities.

[16] Additional details on the modeling assumptions for each of the scenarios are provided in the SEPA Coal Market Assessment Technical Report (ICF 2017c).

Table 3. Scenarios in the Coal Market Assessment[a]

Scenario	Purpose	U.S. Coal Market Conditions (Relative to Base Assumptions)	Asian Coal Market Conditions (Relative to Base Assumptions)	Coal Prices Conditions (Relative to Base Assumptions)	Climate Policy
2015 U.S. and International Energy Policy	Represents impacts of an international climate policy on the coal market as proposed by mid-2015 and the Clean Power Plan	Coal consumption in the United States is lower due to implementation of the Clean Power Plan	Coal consumption is lower due to the implementation of GHG reduction policies	Both domestic and international coal prices are lower due to the lower overall coal demand	Climate policy resembling implementation of the Clean Power Plan and implementation of international GHG reduction policies announced as of mid-2015
No Clean Power Plan	Represents the assumed future state of energy markets in the absence of climate policies	No change from base assumptions	No change from base assumptions	No change from base assumptions	No climate policy implemented in the United States and only those international policies that have been fully implemented by mid-2015
Lower Bound	Represents energy markets where renewable penetration is high and international coal prices and demand are low, making domestic coal exports less attractive to international markets	Coal consumption in the United States is lower due to implementation of the Clean Power Plan and higher assumed Powder River Basin and Uinta Basin coal prices and rail transportation costs	• Lower assumed coal demand due to increased renewables • Lower coal prices due to lower demand	• Higher Powder River Basin and Uinta Basin coal prices due to assumed higher production costs • Lower international coal prices, due to assumed lower production costs	Climate policy resembling implementation of the Clean Power Plan and implementation of international GHG reduction policies proposed as of mid-2015
Upper Bound	Represents energy markets where coal consumption is high, leading to high international demand	Higher coal demand due to lower Powder River Basin and Uinta Basin coal prices	Higher coal demand resulting in higher coal prices	• Lower Powder River Basin and Uinta Basin coal prices due to assumed	No climate policy

Scenario	Purpose	U.S. Coal Market Conditions (Relative to Base Assumptions)	Asian Coal Market Conditions (Relative to Base Assumptions)	Coal Prices Conditions (Relative to Base Assumptions)	Climate Policy
	and prices, making domestic coal exports more attractive to international markets			lower production costs • Higher international coal prices due to increased demand and assumed higher production costs	
Cumulative[b]	Represents the impact of other planned export terminals in the Pacific Northwest	Coal consumption in the United States is lower because the higher amount of exports increases coal prices, which causes a reduction in demand	No change from base assumptions	Domestic coal prices are higher due to increased demand from exports, while international coal prices remain unchanged	No climate policy

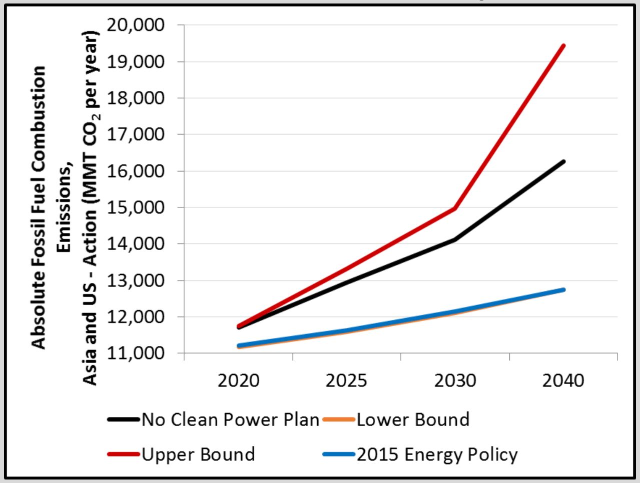
Notes:

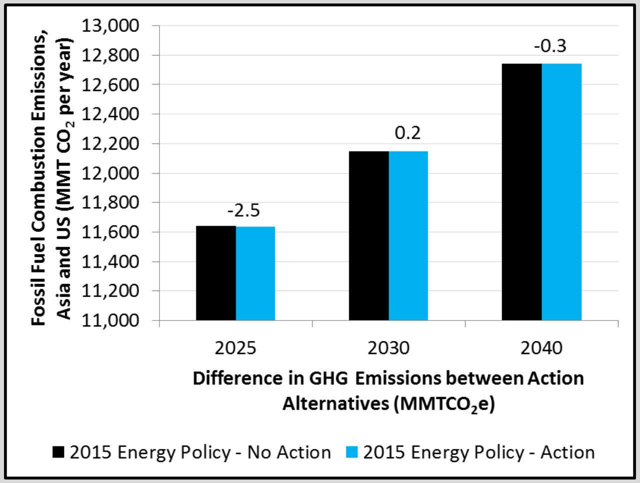
[a] Scenario conditions are defined relative to the No Clean Power Plan scenario.

[b] Further details on the Cumulative scenario can be found in Section 3.1.15, *Net Greenhouse Gas Emissions.*

GHG = greenhouse gases

Comparison of GHG Emissions Across Coal Market Assessment Scenarios





Each coal market assessment scenario represents a range of GHG emissions estimates, based on economic and policy projections from 2016 to 2040. For each scenario, the GHG emissions from Asian coal combustion, U.S. coal combustion, and U.S. natural gas combustion are influenced by a variety of factors, such as coal prices, transportation costs, and the penetration of competing energy sources.

The first chart on the left shows absolute emissions under each coal market scenario for the Proposed Action (noted as the Action Alternative). The scenarios display a significant variation in GHG emissions for coal and natural gas combustion. There is a difference of about 7,000 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) between the 2040 GHG emissions in the Upper Bound and 2015 U.S. and International Energy Policy scenarios, while the Lower Bound and 2015 U.S. and International Energy Policy Scenarios follow nearly the same trajectory. The difference in emissions between the scenarios indicated in the first chart is almost entirely due to the underlying market conditions rather than the influence of the proposed coal export terminal.

To illustrate the influence of the proposed coal export terminal, the second chart on the left indicates the changes in fossil fuel combustion[a] emissions that would occur in Asia and the United States because of the Proposed Action under 2015 U.S. and International Energy Policy scenario conditions. For example in 2040, the no-action under the 2015 U.S. and International Energy Policy scenario would result in combustion emissions of 12,742.7 $MMTCO_2e$ while the combustion emissions resulting from the Proposed Action under 2015 U.S. and International Energy Policy scenario conditions are 12,742.4 $MMTCO_2e$. The resulting net difference is 0.3 $MMTCO_2e$, or 0.002% of emissions. Likewise, changes in absolute emissions between the no-action and the Proposed Action for the other four coal market assessment scenarios are relatively small.

[a] Fossil fuel combustion emissions refer to coal combustion in Asia and the U.S., as well as U.S. natural gas combustion (ICF 2017c).

2.2.2.2 Method for Assembling an Emissions Time Series

Because GHGs accumulate in the atmosphere, a complete assessment of GHGs associated with the Proposed Action requires a characterization of the GHGs over a full analysis period (2018 through 2038). Construction of the coal export terminal would occur between 2018 and 2020. The coal export terminal would become operational in 2021, and reach full capacity by 2028. The GHG analysis estimates emissions for each year during this analysis period as well as for each scenario.

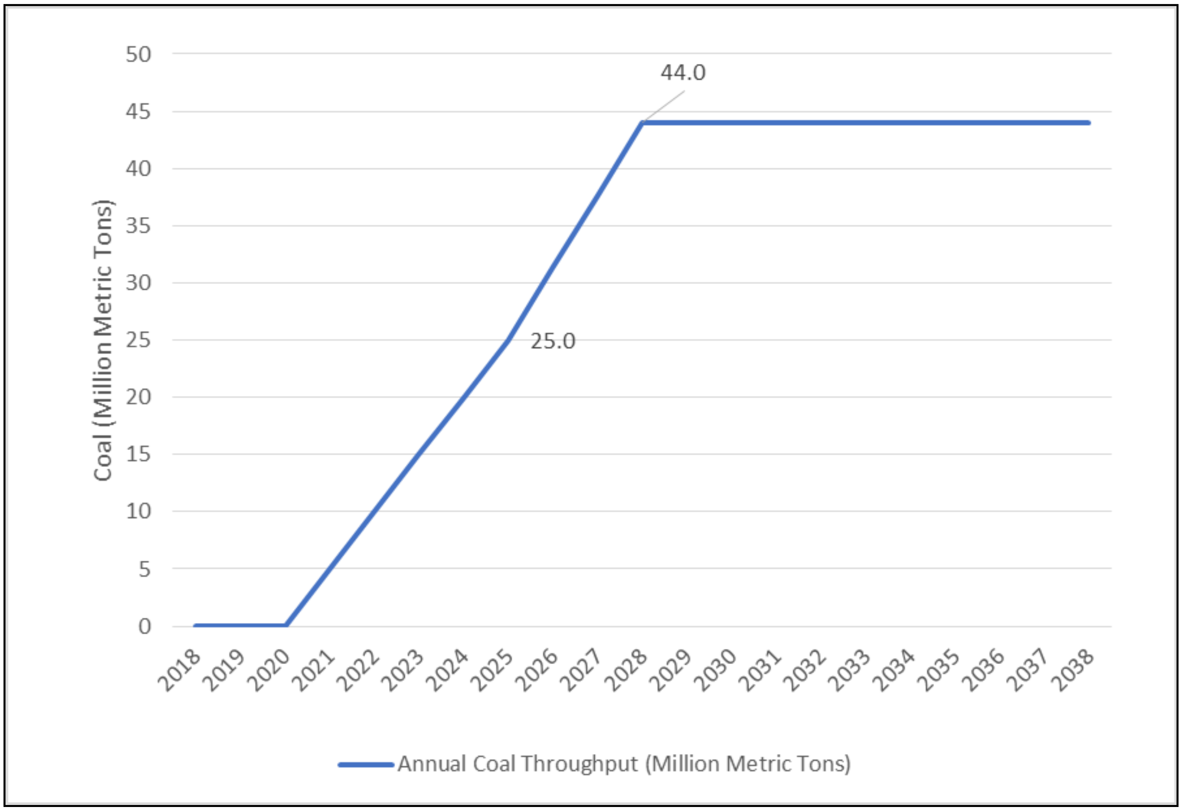
Assembling a complete emissions time series for the GHG analysis requires interpolation of estimates from the other technical reports prepared for the Proposed Action (i.e., coal market, air, and vessel) for the following reasons.

- The coal market assessment provides estimates only for 2025, 2030, and 2040Annual estimates are interpolated from these results.[17]
- The activity data that characterize coal export terminal operations represents conditions in 2028, when the facility is expected to be operational. These data do not reflect coal export terminal start-up, in which the coal throughput increases from zero immediately after construction in 2020 to its full capacity of 44 million metric tons by 2028.

In order to generate estimates of GHG emissions for the full analysis period, the expected coal throughput is increased linearly from zero in 2020 to 25 million metric tons (27.5 million short tons) in 2025. Between 2025 and 2028, the throughput is increased linearly at a slightly faster rate to reach full capacity at 44 million metric tons (48.4 million short tons) by 2028. For this approach, market-influenced emissions are assumed directly proportional to the amount of coal processed by the Proposed Action. The total coal exports for the analysis period add up to 627 million metric tons of coal, including 7 start-up years between 2021 and 2028 and 11 full years of operation from 2028 through 2038 (Figure 5).

[17] This analysis assumes the net impacts from the coal market assessment are 0 in 2020, and thus values are linearly interpolated from 0 in 2020 to the 2025 values in the coal market assessment.

Figure 5. Annual Coal Throughput, 2018-2038



The coal market assessment does not consider a start-up period, so the activity data and emissions estimates for 2025, which assume a full 44 million metric tons of coal throughput, are prorated by 57%; i.e., the ratio of the projected 25 million metric tons of the start-up period and the full 44 million metric ton throughput. This proration factor is applied to all data outputs from the coal market assessment in 2025, including coal extraction, rail transport, coal throughput, fossil fuel combustion emissions,[18] and ocean vessel traffic. Assuming that *net* emissions and activity from operation of the export terminal in the Proposed Action are zero in 2020, the analysis assumes a linear growth to the prorated 2025 data, reaching full operation in 2028, and linear interpolation between the 2030 and 2040 data outputs.

Activity data and emissions estimates are derived and presented in tables in this report only for 2028. Emission estimates for interpolated years from 2021 through 2038 are calculated by interpolating between the emissions values of the closest IPM model run years as well as the calculated value for 2028 (i.e., 2025, 2028, 2030, 2040).

2.2.2.3 Method for Impact Analysis

This section describes the method and approach for each emission source. The methods used for the following emission sources are described: upland and wetland land-cover change; dock dredging during terminal construction and operations—sediment carbon; coal extraction, rail transport, vehicle-crossing delay; coal export terminal construction; coal export terminal operation—equipment operation; coal export terminal operation—electricity consumption; employee

[18] Changes in domestic and international coal combustion are assessed separately.

commuting; vessel idling and tugboat use at coal export terminal; helicopter and pilot boat trips; vessel transport; coal combustion in Asia and the United States; induced natural gas consumption in the United States.

Upland and Wetland Land-Cover Change

The vegetation removal, soil disturbance, and wetland loss associated with construction of the Proposed Action would result in the loss of carbon stocks, the loss of ongoing carbon sequestration, and a reduction in annual emissions in the case of certain wetland vegetation cover types over the analysis period (2018 through 2038).

To estimate the loss of upland carbon stocks from the net change in upland vegetation cover types as a result of construction, estimates of vegetation cover (e.g., aboveground carbon, belowground carbon, understory carbon) and soil carbon stocks (i.e., soil organic carbon) in the project area are based on average carbon stock per area estimates for Cowlitz County taken from the Carbon Online Estimator (National Council for Air and Stream Improvement and U.S. Forest Service 2016). The upland land cover includes forested, scrub-shrub, herbaceous, and managed herbaceous vegetation cover types. The average forested carbon stock per area value may overestimate the actual forested carbon stocks in the project area because the average estimates for Cowlitz County likely include areas with higher carbon stocks (e.g., managed production forests) than the areas within the project area.

These estimates of the carbon stock per area for forested, scrub-shrub, and herbaceous[19] upland vegetation cover types are multiplied by the corresponding changes in area resulting from the construction to estimate the change in carbon stocks associated with construction (e.g., vegetation removal and surface soil disturbance) for the Proposed Action compared to the No Action Alternative. Given the potential high value of the forested carbon stock per area value, these emission estimates likely overestimate the actual construction emissions in the project area but are representative for average areas in Cowlitz County. That said, in the absence of detailed site-level carbon stock surveying, these average values are likely representative and conservative—i.e., they overestimate rather than underestimate emissions.

Loss of ongoing carbon sequestration for the forested, scrub-shrub, and herbaceous[20] upland vegetation cover types are then estimated based on IPCC guidelines (Intergovernmental Panel on Climate Change 2006: Volume 4). These estimates of the lost sequestration per area for forested, scrub-shrub, and herbaceous[21] upland vegetation cover types are multiplied by the corresponding changes in area resulting from construction over the analysis period (2018 through 2038) to estimate the lost sequestration.

Table 4 shows the emission factors (lost carbon stock and lost sequestration values) derived for the upland land cover type.

[19] There is only one carbon stock per area factor available for herbaceous upland vegetation cover type. This carbon stock density is applied for both herbaceous and managed herbaceous vegetation cover types. The carbon in both of these systems predominantly resides in the soil, and is largely independent of management.

[20] The annual carbon sequestration for the forested and scrub-shrub vegetation types is based on the aboveground net biomass growth in natural temperate continental forests in North America. The annual carbon sequestration for the herbaceous vegetation type is assumed zero because the soil carbon gains and losses were assumed to have reached an equilibrium for an established herbaceous system.

[21] The same carbon stock density is applied for both herbaceous and managed herbaceous vegetation cover types since the carbon in both of these systems predominantly resides in the soil.

Table 4. Upland Emission Factors

Land Cover Category	Vegetation Cover Type	One-time Lost Carbon Stock (metric tons CO_2e/acre)[a]	Annual Lost Sequestration (metric tons CO_2e/acre/year)[b]
Upland	Forested	510.5	2.8
	Scrub-shrub	325.6	2.8
	Herbaceous	140.7	0
	Managed herbaceous	140.7	0

Notes:
[a] One-time lost carbon stock values derived from Carbon On-Line Estimator search result in information for Cowlitz County (National Council for Air and Stream Improvement and U.S. Forest Service 2016).
[b] Annual lost sequestration values are from IPCC (2006)
GHG = greenhouse gas; CO_2e = carbon dioxide equivalent

To estimate the loss of wetland carbon stocks, estimates of vegetation cover carbon stocks in the project area are also based on average carbon stock per area estimates for Cowlitz County taken from the Carbon Online Estimator, with the soil carbon stocks taken from a study by the U.S. Department of Agriculture Forest Service (Trettin and Jurgensen 2003). These estimates of the carbon stock per area for forested, scrub-shrub, and herbaceous wetland cover types are multiplied by the corresponding changes in wetland area resulting from construction to estimate the change in carbon stocks associated with construction.

To estimate the loss of ongoing carbon sequestration for the forested, scrub-shrub, and herbaceous wetland vegetation cover types, representative estimates of annual carbon sequestration for wetlands assumed similar to those in the project area are from a study by Hansen (2009). Based on values reported by Trettin and Jurgensen (2003), these annual carbon sequestration estimates are adjusted to include the reduction in annual carbon dioxide and methane emissions for wetlands.

These adjusted estimates of the lost sequestration and reduction in emissions per area for forested, scrub-shrub, and herbaceous wetland vegetation cover types are multiplied by the corresponding changes in area resulting from the construction over the analysis period (2018 through 2038) to estimate the lost sequestration and reduction in emissions.

Table 5 shows the emission factors (i.e., lost carbon stock and lost sequestration and reduction in emission values) derived for the wetland vegetation cover types.

Table 5. Wetland Emission Factors

Land Cover Category	Vegetation Cover Type	One-time Lost Carbon Stock ($MtCO_2e$/acre)[a-]	Annual Lost Sequestration ($MtCO_2e$/acre/year)[b]
Wetland	Forested	451.43	–5.51
	Scrub-shrub	266.52	–2.12
	Herbaceous	81.61	1.26

Notes:

[a] One-time lost carbon stock values are derived from Carbon On-Line Estimator search result information for Cowlitz County (National Council for Air and Stream Improvement and U.S. Forest Service 2016), with the soil carbon stocks taken from a study by the Trettin and Jurgensen (2003)

[b] Annual lost sequestration values are from a study by Hansen (2009), adjusted to include the reduction in annual carbon dioxide and methane emissions taken from Trettin and Jurgensen (2003)

GHG = greenhouse gas; CO_2e = carbon dioxide equivalent; $MtCO_2e$ = metric tons of carbon dioxide equivalent

Dock Dredging During Terminal Construction and Operations—Sediment Carbon

To estimate the potential loss of sediment carbon associated with dock dredging during coal export terminal construction and operations, the volume of sediment removed during coal export terminal construction and operations is multiplied by the density of the sediment, the total solids percentage in the sediment, and the total organic carbon percentage in the sediment. The resulting sediment carbon mass is converted to CO_2 equivalents. The density of the sediment is based on engineering density information available online (Engineering ToolBox 2016). The total organic carbon percentage and the total solids percentage in the sediment are based on the chemical analysis results value reported for the existing bulk product terminal (Dredged Material Management Program 2016).

Dredged material disposal would be determined through the Dredged Material Management Program process and options could include flow lane disposal for beneficial use in the Columbia River, or upland use of dredged material for pre-loading stockpile areas (Grette Associates 2014). For these dredge disposal options, how much of the organic carbon contained in the sediment that will actually be exposed to the air, oxidized, and emitted as carbon dioxide is unknown. As a result, the estimates represent the potential loss of sediment carbon, and likely overestimate the actual sediment carbon emissions associated with dock dredging during terminal construction and operations.

Table 6 shows the sediment carbon assumptions.

Table 6. Sediment Carbon Assumptions

Dock Dredging Period	Sediment Removed (cubic yard)	Sediment Density (lbs/ft^3)[a]	Total Solids (%)[b]	Total Organic Carbon (%)[c]
Construction	500,000	80	78.84	0.271
Annual Operations	100,000	80	78.84	0.271

Notes:
1 cubic yard = 27 cubic feet; 1 pound = 0.00454 metric tons; 1 metric ton carbon = 44/12 metric tons CO_2e
[a] Sediment density value is based on engineering density information available online (Engineering ToolBox 2016).
[b] Total solids percentage value is from Dredged Material Management Program Suitability Determination for the existing bulk product terminal (Dredged Material Management Program 2016).
[c] Total organic carbon percentage value is from the Suitability Determination for the existing bulk product terminal (Dredged Material Management Program 2016).

Coal Extraction

The coal market assessment indicates that coal extraction in the United States would increase in all four scenarios under the Proposed Action, as the export of coal through the coal export terminal would cause additional coal to be mined in the United States beyond that which is extracted for domestic consumption under the no-action. While coal production may increase, decrease, or stay the same across the U.S coal regions depending on the year and the scenario, in general the net change in extracted coal would come primarily from the Powder River Basin in Montana and Wyoming and the Uinta Basin in Utah and Colorado. Some change in domestic coal extraction is also expected in other regions outside the Powder River Basin and Uinta Basin due to indirect effects on the domestic coal market by the Proposed Action.

The coal market assessment also indicates that coal extraction outside the United States would decrease in all four scenarios under the Proposed Action, as the export of coal through the terminal would reduce the demand for coal mining in other countries beyond what is currently extracted under the no-action. While coal extraction may increase, decrease, or stay the same across international coal regions depending on the year and the scenario, in general, the avoided extraction of competing coal (i.e., coal extraction in international markets that would no longer occur due to the substitution of U.S.-based coal) would occur primarily in Australia, Indonesia, Russia, India, and China. Some change in international coal extraction is expected in other regions, both within and outside Asia.

Coal extraction from regions assessed in the coal market assessment (i.e., the Powder River Basin, Uinta Basin, other U.S. regions, and non-U.S. regions) would result in GHG emissions from:

- Energy consumption (electricity and diesel fuel) for mining operations, including overburden removal, coal extraction, and reclamation.
- Methane from surface and underground mining.

Under this approach, the indirect coal extraction GHG emissions from the Proposed Action are calculated by applying the GHG emission factors for each source of indirect emissions to the volumes of U.S. coal extraction that would be induced by the Proposed Action, covering the Powder River Basin, the Uinta Basin, and other U.S. coal regions. These GHG estimates are offset by GHG emissions from competing coal extraction outside the United States, primarily in Australia, Indonesia, Russia, and China. From these annual estimates of net GHG emissions, the total indirect GHG emissions are calculated for coal extraction that would result from the Proposed Action during operations from 2021 through 2038.

The following sections describe the methods for assessing the GHG emissions impacts from coal extraction for each of the coal extraction regions impacted by the Proposed Action.

Coal Extraction from U.S. Mines

For all scenarios under the Proposed Action, surface mining is expected to increase in the United States, with changes in coal extraction occurring primarily in the Powder River Basin and the Uinta Basin during the analysis period. Smaller changes in surface coal extraction occur in other U.S. regions.

Diesel fuel consumption needed for each ton of extracted at the surface mine as part of mine operation is estimated based on a recent life-cycle assessment study of coal exports from the Powder River Basin from the National Energy Technology Laboratory (Skone et al. 2016). The result is 0.351 gallon of diesel fuel per metric ton of coal mined. Based on estimates provided in Skone et al. (2016), the electricity consumption needed for mine operation (e.g., equipment, lighting) is estimated to be 11,500 megawatt-hours per million metric ton of coal mined.

The GHG emissions from diesel fuel combustion are estimated using emission factors from Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model (Argonne National Laboratory 2016). The GHG emissions from electricity production are based on EPA's eGRID annual combustion output emissions rate for states where surface coal extraction is expected to change: Colorado, Illinois, Indiana, Montana, Pennsylvania, Utah, Virginia, West Virginia, Wyoming, Alabama, Arizona, Arkansas, Kansas, Kentucky, Maryland, New Mexico, North Dakota, Oklahoma, Tennessee, Texas, and Mississippi (U.S. Environmental Protection Agency 2017).

Based on estimates provided in Spath et al. (1999), the electricity consumption needed for underground mine operation (e.g., equipment, lighting) is estimated to be 12,755 megawatt-hours per million metric ton of coal mined. The GHG emissions from electricity production use the same EPA eGRID emission factors as the surface mining assessment.

The surface mining methane emissions specific to each U.S. surface mining coal extraction basin are estimated per metric ton of coal mined based on data provided in EPA's 1990–2014 GHG Inventory. Underground mining emissions specific to each basin are unavailable. To estimate underground mining methane emissions, a U.S. average emission factor based on total 2014 U.S. underground mining emissions and production data from the EPA GHG Inventory was used for all underground basins (U.S. Environmental Protection Agency 2016b). For each basin a weighted average methane emission factor was calculated based on the share of basin underground and surface mining production (Mining Safety and Health Administration 2016) and underground and surface mining emission factors. Emission factors for surface and underground mining include both emissions directly from mining and from post-mining activities (e.g., handling, transportation). Table 7 presents a summary of the consumption and emission factors used to assess the GHG emissions from U.S. coal extraction.

Table 7. U.S. Mining Coal Extraction Factors[a]

Material Input/Process	Factor	Unit	Source
Surface Mining Electricity Consumption	11,500	MWh/Million Mt of Coal	Skone et al. 2016
Underground Mining Electricity Consumption	12,755	MWh/Million Mt of Coal	Spath et al. 1999
Electricity emissions – Colorado	0.723	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Illinois	0.452	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Indiana	0.900	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Montana	0.591	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Pennsylvania	0.452	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Utah	0.809	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Virginia	0.401	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – West Virginia	0.903	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Wyoming	0.913	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Alabama	0.481	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Arizona	0.507	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Arkansas	0.587	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Kansas	0.644	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Kentucky	0.946	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Maryland	0.531	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – New Mexico	0.768	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – North Dakota	0.827	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Oklahoma	0.618	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Tennessee	0.487	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Texas	0.540	MtCO2e/MWh	U.S. EPA 2017
Electricity emissions – Mississippi	0.450	MtCO2e/MWh	U.S. EPA 2017
Diesel consumption	0.351	Gallons/Mt of Coal	Skone et al. 2016
Diesel combustion emissions	0.011	MtCO2e/Gallon	Argonne National Laboratory 2016
Surface Mining Methane Emissions – Central Appalachia Basin – Virginia	0.025	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Central Appalachia Basin – West Virginia	0.025	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Central Appalachia Basin – East Kentucky	0.024	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Illinois Basin	0.035	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Northern Great Plains (Powder River Basin) – Wyoming and Montana	0.020	MtCO2e/Mt of Coal	U.S. EPA 2016b

Material Input/Process	Factor	Unit	Source
Surface Mining Methane Emissions – Northern Great Plains (Powder River Basin) – North Dakota	0.005	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Northern Appalachia Basin	0.061	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Rockies (Green River Basin)	0.034	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Rockies (Uinta Basin)	0.016	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Rockies (San Juan Basin)	0.007	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Rockies (Raton Basin)	0.032	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – Warrior Basin	0.029	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – West Interior (Arkoma Basin)	0.071	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – West Interior (Forest City, Cherokee Basins)	0.033	MtCO2e/Mt of Coal	U.S. EPA 2016b
Surface Mining Methane Emissions – West Interior (Gulf Coast Basin)	0.011	MtCO2e/Mt of Coal	U.S. EPA 2016b
Underground Mining Methane Emissions – U.S. Average	0.171	MtCO2e/Mt of Coal	U.S. EPA 2016b

[a] Emission factors for surface and underground mining include both mining and post mining activities.

Sources: Argonne National Laboratory 2016, Skone et al. 2016, U.S. Environmental Protection Agency 2015b, U.S. Environmental Protection Agency 2016b

Mt = metric tons of material; MWh = megawatt-hour; CO_2e = carbon dioxide equivalent

Coal Extraction from International Mines

For all scenarios under the Proposed Action, with the exception of China in the Upper Bound scenario, coal mining is expected to decrease outside the United States, with changes in coal extraction occurring primarily at underground and surface coal mines in Australia, Indonesia, India, Russia, and China across the analysis period. Smaller changes in surface and underground coal extraction are expected to occur in Canada and South Africa.

For each of these international regions, coal extraction emissions were estimated using region-specific emission factors for coal mining methane emissions, electricity use, and diesel fuel use.

Indirect GHG emissions from methane released in coal mining were obtained from the latest United Nations Framework Convention on Climate Change (UNFCCC) GHG inventory data for methane emissions from underground and surface coal mining emissions (United Nations Framework Convention on Climate Change 2015). These emissions estimates include underground and surface mining and post-mining fugitive emissions but exclude abandoned mine emissions, as they are not directly related to ongoing coal extraction.

China, Indonesia, and India did not report coal mining methane emissions to UNFCCC; for these regions this analysis used average Tier 1 underground and surface mining, including mining and post-mining, from IPCC GHG inventory guidelines (Intergovernmental Panel on Climate Change 2006). These IPCC emission factors were combined with Global Methane Initiative data for shares of surface mining and underground mining of total coal production. According to the Global Methane Initiative data, Indonesia produced coal from 100% surface mines, China produced coal from 10% surface and 90% underground mines, India produced coal from 90% surface and 10% underground mines, and South Africa produced coal from 51% underground and 49% surface mines. For China, the emission factor was adjusted to account for quantities of utilized methane based on Global Methane Initiative data (Global Methane Initiative 2015). Utilized methane represents coal-mining methane that is captured and consumed on site or off site. This method for China's emission factor follows IPCC guidelines (Intergovernmental Panel on Climate Change 2006).

For regions where UNFCCC methane emission data were used, a coal mining methane emission factor was derived by dividing the total methane emissions for the most recent available year (2014) by Energy Information Agency coal production data for the specific region and year (2017).

Electricity and diesel consumption from on-site mining activities came from an Ecoinvent report on environmental impact inventories from international energy systems (Dones et al. 2007 in International Energy Agency 2015). Region-specific electricity emission factors as indicated in the International Energy Agency were applied to calculate indirect CO_2 emission based on the Dones et al. consumption values (International Energy Agency 2015), and used diesel combustion emission factors from the Argonne National Laboratory's GREET model (Argonne National Laboratory 2016).

Table 8 presents a summary of the consumption and emission factors used to assess the GHG emissions from international coal extraction.

Table 8. International Underground and Surface Mining Coal Extraction Factors

Material Input/Process	Factor	Unit	Source
Australia – electricity consumption	17.9	kWh/Mt of Coal	Dones et al. 2007
Canada – electricity consumption	25.1	kWh/Mt of Coal	Dones et al. 2007
China – electricity emissions	12.9	kWh/Mt of Coal	Dones et al. 2007
India – electricity consumption	12.9	kWh/Mt of Coal	Dones et al. 2007
Indonesia – electricity consumption	12.9	kWh/Mt of Coal	Dones et al. 2007
Russia – electricity consumption	93.0	kWh/Mt of Coal	Dones et al. 2007
South Africa – electricity consumption	13.9	kWh/Mt of Coal	Dones et al. 2007
Australia – electricity emissions	798.38	g CO_2/kWh	IEA 2015b
Canada – electricity emissions	158.4	g CO_2/kWh	IEA 2015b
China – electricity emissions	711.9	g CO_2/kWh	IEA 2015b
India – electricity emissions	789.24	g CO_2/kWh	IEA 2015b
Indonesia – electricity emissions	761.21	g CO_2/kWh	IEA 2015b
Russia – electricity emissions	439.37	g CO_2/kWh	IEA 2015b
South Africa – electricity emissions	926.40	g CO_2/kWh	IEA 2015b
Australia – diesel consumption	65.5	MJ/Mt of Coal	Dones et al. 2007
Canada – diesel consumption	33.7	MJ/Mt of Coal	Dones et al. 2007
China – diesel emissions	24.2	MJ/Mt of Coal	Dones et al. 2007
India – diesel consumption	24.2	MJ/Mt of Coal	Dones et al. 2007
Indonesia – diesel consumption	24.2	MJ/Mt of Coal	Dones et al. 2007
Russia – diesel consumption	41.8	MJ/Mt of Coal	Dones et al. 2007
South Africa – diesel consumption	48.3	MJ/Mt of Coal	Dones et al. 2007
Diesel combustion emissions	0.011	MtCO2e/Gallon	Argonne National Laboratory 2016
Australia – Coal Mine Methane	0.04	Mt CO_2e/Mt of Coal	UNFCCC 2017, EIA 2016
Canada – Coal Mine Methane	0.02	Mt CO_2e/Mt of Coal	UNFCCC 2017, EIA 2016
China – Coal Mine Methane	0.30	Mt CO_2e/Mt of Coal	IPCC 2006, GMI 2015, EIA 2016
India – Coal Mine Methane	0.05	Mt CO_2e/Mt of Coal	IPCC 2006, GMI 2015
Indonesia – Coal Mine Methane	0.02	Mt CO_2e/Mt of Coal	IPCC 2006, GMI 2015
Russia – Coal Mine Methane	0.15	Mt CO_2e/Mt of Coal	UNFCCC 2017, EIA 2016
South Africa – Coal Mine Methane	0.19	Mt CO_2e/Mt of Coal	IPCC 2006, GMI 2015

Sources: Argonne National Laboratory 2016, Intergovernmental Panel on Climate Change 2016, Dones et al. 2007, Global Methane Initiative 2015, IEA 2015, UNFCCC 2017

Mt = metric tons of material; kWh = kilowatt-hour; g = grams of material; MJ = megajoule; CO_2 = carbon dioxide; CO_2e = carbon dioxide equivalent; IPCC = Intergovernmental Panel on Climate Change; GMI = Global Methane Initiative

Uncertainty Associated with Methane Emissions from Coal Extraction

Methane emissions during coal extraction represent a major source of GHG emissions in the production of coal. In particular, methane concentrated in coal deposits is released during extraction processes. The amount of methane concentrated in coal deposits varies significantly between regions, but underground deposits have much higher concentrations than surface deposits (Intergovernmental Panel on Climate Change 2006).

Measurements and estimates of methane released during mining can be highly uncertain, even at the mine or basin level. As indicated in the adjacent table, the uncertainty for coal mine methane emissions can be well over 100%.[a] The majority of international emission factors used in the GHG analysis are from UNFCCC sources, where participating countries report both mining and post-mining methane for underground and surface activities.

Tier Methodology	Underground Mining		Surface Mining	
	Mining	Post-Mining	Mining	Post-Mining
Tier 3 - Mine Specific Factors	+/-2-30%		N/A	
Tier 2 - Basin Specific Factors	+/-50-75%	+/-50%	+/-200%	+/-50%
Tier 1 - Global Averages	+/-200%	+/-300%	+/-300%	+/-300%

Source: Intergovernmental Panel on Climate Change 2006

However, which Tier each country used and the associated uncertainty are not reported. For countries that do not report coal mining emissions (i.e., China, Indonesia, India, and South Africa for this assessment), IPCC (2006) Tier 1 emission factors are used as shown in the table to the left. These factors have uncertainty ranges from +/- 200 to 300 percent.

Source Category	IPCC Tier 1 Methane Emission Factors - Mining and Post-Mining ($Mt\ CO_2e/Mt$ coal)		
	Low	Average	High
Underground Mining	0.18	0.34	0.49
Surface Mining	0.01	0.02	0.04

Source: Intergovernmental Panel on Climate Change 2006

In general, the uncertainty associated with the GHG emission estimates from coal mining are an order of magnitude higher than those associated with coal combustion. As an example, the table to the right contrasts the source uncertainties for emission measurements from coal methane and fossil fuel combustion from the latest U.S. Environmental Protection Agency GHG inventory estimates.[b] As indicated, coal mining methane emissions have a relatively higher uncertainty than those from fossil fuel combustion.

Source Category	Uncertainty Range for 2014 GHG Inventory	
	Low	High
Coal Mining Methane	-12%	15%
Fossil Fuel Combustion	-2%	5%

Source: U.S. EPA 2016b

Coal methane emissions from extraction are key contributors to net GHG emissions in the GHG analysis. Because of this contribution, the net GHG estimates are estimated for both with and without coal extraction emissions for each of the coal market assessment scenarios.

[a]IPCC uncertainties for coal mine methane emissions reflect ranges of percent deviations from the reported emission factors and are based on expert judgement (IPCC 2006).
[b]These values reflect the 95% confidence interval in percent deviations above and below the reported 2014 value for each source category (U.S. EPA 2016b).

Coal methane emissions from extraction are key contributors to net GHG emissions in the GHG analysis. Because of this contribution, the net GHG estimates are estimated both with and without coal extraction emissions. The uncertainties of these estimates are detailed in the text box above.

China, a major driver of this assessment's extraction emissions, currently produces large amounts of coal from methane-intensive underground mines. China has greatly expanded coal mine methane recovery and utilization over the past decade (Global Methane Initiative 2015). Based on its recently developed Intended Nationally Determined Contributions, China plans to continue to enhance vented methane recovery and utilization (United Nations Framework Convention on Climate Change 2015), but this is not reflected in this analysis due to data restrictions. Coal mine methane utilization values were taken into account in the emission factor for China based on data reported as of 2013 (Global Methane Initiative 2015). Increases in coal mine methane utilization in China would result in a decrease in the emission factor for China and an increase in the resulting net GHG estimates for each scenario (i.e., the offsetting of underground mined coal in China would result in offsetting a smaller quantity of methane from the estimate of net GHG emissions).

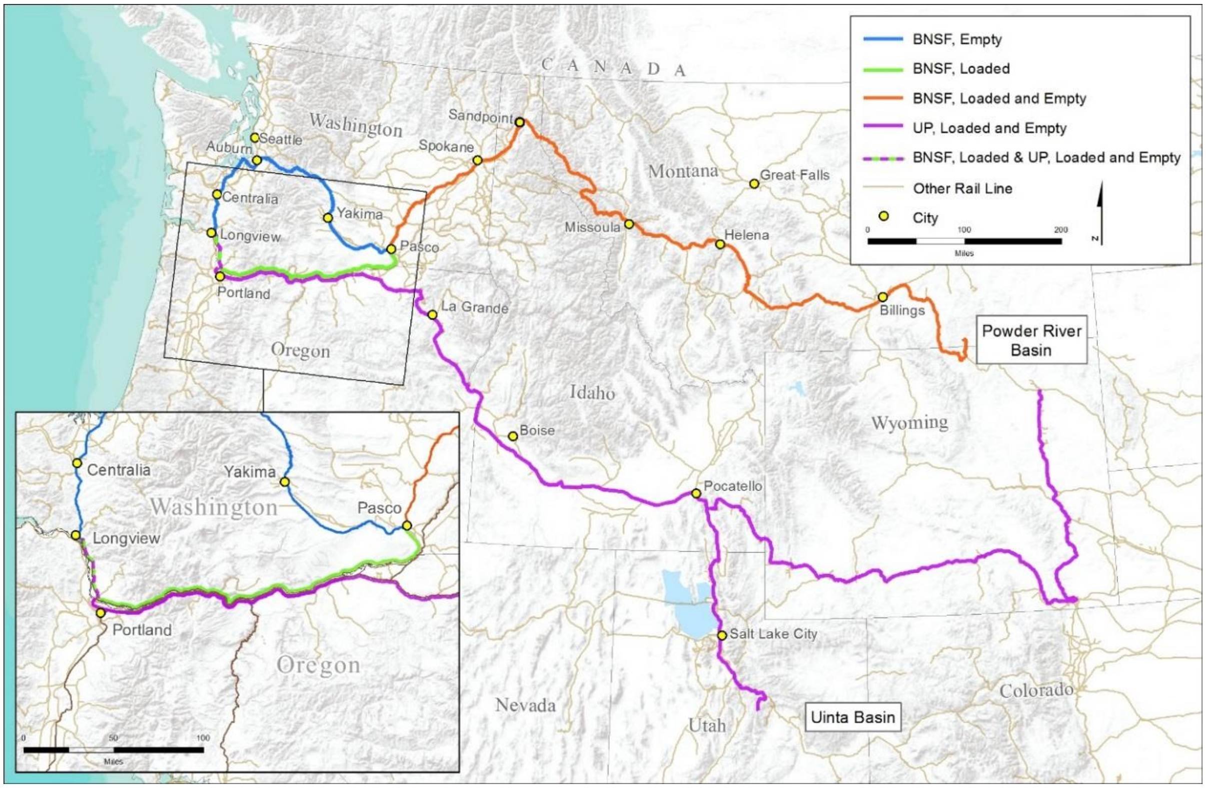
Rail Transport

Rail Transport to Washington State

Indirect sources of GHG emissions from coal transport from the Uinta and Powder River Basins to Washington State include diesel combustion emissions from locomotive operation of empty and loaded Proposed Action-related trains. The Uinta Basin is located in Colorado and Utah, whereas the Powder River Basin is located in Montana and Wyoming. The distances from six coal extraction sites (one each in Colorado and Utah; two in Montana; two in Wyoming) to Washington State range from 627 miles to 946 miles by rail. For this analysis, each train is assumed to consist of four locomotives and 125 rail cars, each loaded with 121 metric tons of coal[22] (ICF and Hellerworx 2017). For the return trip, this analysis assumes that the train would make a return trip to the coal basins with four locomotives and empty rail cars. Figure 6 provides an illustration of coal train routes from the Powder River Basin and the Uinta Basin to the project area.

[22] The approximate amount of coal that would be required to transport 44 million metric tons of coal in 8 loaded unit trains, 125 rail cars per day, 365 days per year.

Figure 6. Rail Transport of Coal to the Project Area



To calculate emissions, the gross mass of the loaded and empty coal trains is derived from BNSF data to determine the gross ton-miles of rail traffic associated with each scenario.[23] Table 9 provides an overview of the mass associated with the locomotives, the loaded coal, and the rail cars.

Table 9. Mass of Coal Train Components

Train Component	Mass (Metric Tons)
Locomotive (one)	196
Rail car (one)	19
Coal per car	121
Gross train mass (full)	18,222
Gross train mass (empty)	3,154
Source: ICF and Hellerworx 2017	

The mass of the trains is multiplied by the total distance traveled to bring coal from mines in Colorado, Montana, Utah, and Wyoming to Washington State. The relative amount of train traffic from each extraction site is dependent on the coal market assessment scenario and year. For example, as the coal throughput at the coal export terminal remains constant, the relative shares of coal coming from the Uinta and Powder River Basins shifts. Table 10 provides estimates of rail

[23] Gross-ton miles refer to ton-miles travelled that include the mass of the railcars and locomotives in addition to the mass of the cargo.

distances from coal extraction sites to Washington State for the coal supply regions modeled that could export from the project area.

Table 10. Coal Supply Regions and Distances to Washington State

Coal Type	Rail Distance to Washington State (Miles)
Montana Powder River Basin Coal	797
Montana Signal Peak	760
Wyoming Powder River Basin Coal (8,400 Btu/lb)	946
Wyoming Powder River Basin Coal (8,800 Btu/lb)	946
Colorado Uinta Basin Coal	839
Utah Uinta Basin Coal	1,013

Source: Distances estimated via geographic information system mapping.
Btu/lb = British thermal units per pound

The fuel consumption for transport to Washington State is estimated by multiplying the ton-miles travelled for each data year by a fuel consumption per ton-mile factor for average locomotive diesel consumption.[24] The GHG emissions are estimated by multiplying the total fuel consumption by a rail diesel-specific combustion factor, as shown in Table 11.

Table 11. Emission Factors from Rail Diesel Fuel

Greenhouse Gas	Emission Factor ($MtCO_2e$/1,000 gallons)
Carbon dioxide	10.26
Methane	0.01
Nitrous oxide	0.02
Total	**10.29**

Source: U.S. Environmental Protection Agency 2015a
$MtCO_2e$ = metric tons of carbon dioxide equivalent

Rail Transport in Washington State beyond Cowlitz County

Indirect sources of GHG emissions from rail transport of coal in Washington State include diesel combustion emissions from locomotives. GHG emissions from rail transport of coal within Washington State to the border of Cowlitz County are estimated using the same approach as for transport to Washington State. Powder River and Uinta Basin coal would be transported through Washington State to Cowlitz County via Pasco and through the Columbia River Gorge, entering Cowlitz County near Woodland. Empty trains returning to the Powder River Basin would take a longer northern route (via Stampede Pass) whereas empty trains returning to the Uinta Basin return along the southern route. Therefore, returns to Powder River Basin are longer (Table 12).

[24] An estimate of 833 gross-short ton miles per gallon of diesel is used (BNSF Railway Company 2013).

Table 12. Coal Types and Distances within Washington State beyond Cowlitz County

Coal Type	Loaded Train Distance (Miles)	Empty Train Distance (Miles)
Powder River Basin coal	401	488
Uinta Basin Coal	18	18

Note: Estimate does not include distance travelled within Cowlitz County
Source: ICF and Hellerworx 2017

Rail Transport in Cowlitz County

Direct sources of GHG emissions from rail transport of coal in Cowlitz County include diesel combustion emissions from the operation of locomotives in Cowlitz County. Emissions include round-trip emissions from loaded and empty trains on the BNSF main line as well as the Reynolds Lead and BNSF Spur leading to the project area from the BNSF main line. Loaded trains travel to the project area from near Woodland, whereas empty trains travel along the BNSF main line to near Vader. GHG emissions from rail transport of coal from the border of Cowlitz County to the project area are estimated using the same approach as for the transport outside the county. Emissions are estimated from the project area to the county border; a distance of 25.1 miles for loaded trains entering Cowlitz County and 28.5 miles for empty trains leaving the county (Table 13).

Table 13. Rail Distances Traveled within Cowlitz County

Rail Route	Loaded Train Distance (Miles)	Empty Train Distance (Miles)
Cowlitz County Border to Longview Junction	17.9	-
Longview Junction to project area	7.1	7.1
Longview Junction to Cowlitz County Border	-	21.4
Total	**25.1**	**28.5**

Source: ICF and Hellerworx 2017

Locomotive Operation in the Project Area

Direct GHG emissions at the project area for the Proposed Action include emissions from the movement of coal trains around the 1.65- mile loop, the on-site idling of coal trains, and the operation of a switch locomotive to move cars and assemble trains for departure. The analysis assumes that it takes 1.85 hours to unload a 125-car unit train, each train has a 5-hour idle period prior to departing the facility, and the switch locomotive operates for 8 hours a day. This emission source includes the sum of these three activities. Emission factors for line-haul locomotives are based on projected changes in the locomotive fleet over the next 30 years (U.S. Environmental Protection Agency 2009b). These emission factors are based on engine load and associated fuel consumption during transport to and from the facility, time to unload coal from the train cars, and total annual coal throughput. The power demand is proportional to engine load, which varies in intensity depending on whether the locomotive is hauling freight or idling. The fuel consumption is estimated based on the power demand, which is estimated based on the engine load and duration of the activity. The fuel consumption is then multiplied by fuel combustion emission factors for locomotives as provided in Table 14.

Table 14. Emission Factors for Locomotives

Greenhouse Gas	Emission Factor ($MtCO_2e$/ 1,000 gallons)
Carbon dioxide	10.23
Methane	<0.1
Nitrous oxide	0.1
Total	**10.31**

Source: U.S. Environmental Protection Agency. 2009b. *Emission Factors for Locomotives.*
$MtCO_2e$ = metric tons of carbon dioxide equivalent

Vehicle-Crossing Delay

Direct sources of GHG emissions from vehicle-crossing delay include the incremental fuel emissions caused by vehicle delay at grade crossings in Cowlitz County due to train traffic to the project area. This emission source is based on existing rail infrastructure. GHG emissions are determined by estimating the gate downtime per day at grade crossings along the BNSF Spur and Reynolds Lead (between the BNSF main line and the project area) and at public at-grade crossings along the BNSF main line in Cowlitz County, and then estimating the average delay per vehicle for each crossing. The emission estimate does not consider any track improvements to the Reynolds Lead and BNSF Spur. Emissions are estimated based on the average volume of vehicle traffic for each crossing. The fleet mix, or relative shares of vehicle types delayed at the crossing, is assumed representative of Cowlitz County as a whole, and is derived from the MOtor Vehicle Emission Simulator (MOVES) model (U.S. Environmental Protection Agency 2014a). The MOVES model provides emission factors for each vehicle type in grams per mile travelled, which are converted into vehicle delay emissions by multiplying by the assumed average vehicle speed of 2.5 miles per hour.[25] The mix of vehicles and their contribution to the weighted average Cowlitz County vehicle traffic emission factor is shown in Table 15.

[25] The MOVES emission factor for vehicle idling is based on a slow operation speed of 2.5 miles per hour.

Table 15. Weighted Vehicle Fleet Mix for Cowlitz County, 2028

Vehicle Type	Vehicle Speed (mph)	Emission Factor (g/mi)[a]	Fraction of Each Vehicle (%)[b]	Weighted Emission Factor (g CO_2e/ vehicle-hour)
Combination long-haul truck	2.5	1,866	1.13	52.71
Combination short-haul truck	2.5	1,821	0.82	37.33
Intercity bus	2.5	1,909	0.01	0.48
Light commercial truck	2.5	375	8.07	75.57
Motor home	2.5	1,259	0.88	27.70
Motorcycle	2.5	443	3.22	35.67
Passenger car	2.5	273	48.12	328.01
Passenger truck	2.5	367	33.14	304.23
Refuse truck	2.5	1,839	0.15	6.90
School bus	2.5	1,253	0.36	11.28
Single unit long-haul truck	2.5	1,108	0.16	4.43
Single unit short-haul truck	2.5	1,153	3.92	112.99
Transit bus	2.5	1,648	0.04	1.65
Total			**100.00**	**998.95**

Notes: MOVES assumes a vehicle speed of 2.5 miles per hour to simulate idling emissions.
Sources:
[a] U.S. Environmental Protection Agency 2014a
[b] ICF 2017b

The delay is estimated for each road segment in the county and described as the total minutes of delays (in vehicle-hours) as well as the total vehicles affected. The emissions are estimated by multiplying the above fleet mix by vehicle-specific emission factors (in grams per vehicle-hour of delay) and then by the total amount of delay over the period of a year (Table 16).

Table 16. Activity Data for Vehicle Delay in Cowlitz County, 2028

Street	Daily Trains	Avg. Train Length (feet)	Train Speed (mph)	Avg. Daily Traffic in Both Directions (veh/day)	Number of Lanes in Both Directions	Total Delay (min /day)	Vehicles Delayed per Day (veh/day)
Study Crossings along the Reynolds Lead and BNSF Spur							
Industrial Way (SR 432)	16	5,944	10	12,100	2	4,315	975
Oregon Way (SR 433)	16	5,944	10	18,770	4	6,379	1,513
California Way	16	5,946	8	4,800	2	2,401	477
3rd Avenue (SR 432)	16	5,946	8	20,720	4	10,893	2,060
Dike Road	16	6,301	10	1,100	2	371	94
Project access (opposite 38th Avenue)	16	5,944	5	1,340	2	1,522	209
Weyerhaeuser Access (opposite Washington Way)	16	5,944	8	3,900	4	1,840	388
Weyerhaeuser Norpac Access	16	5,944	10	800	2	240	64
Public At-Grade Crossings along the BNSF Main Line in Cowlitz County							
Taylor Crane Road in Castle Rock	8	5,546	50	50	2	0.4	0.5
Cowlitz Street in Castle Rock	8	5,546	50	1,450	2	13	14
Cowlitz Gardens Road in Kelso	8	5,546	62	850	2	6	7
Mill Street in Kelso	8	5,546	40	3,000	2	39	35
S River Road/ Yew Street in Kelso	8	5,546	40	2,200	2	28	25
Toteff Road/ Port Road in Kalama	8	5,546	62	1,450	2	10	12
W Scott Avenue in Woodland	8	5,546	62	3,100	2	21	26
Davidson Avenue in Woodland	8	5,546	62	2,350	2	16	20
Whalen Road in Woodland	8	5,546	62	1,800	2	12	15

Source: ICF and DKS Associates 2017.

Coal Export Terminal Construction

Direct sources of GHG emissions from construction include operation of the construction equipment itself as well as the vehicles to bring employees and construction materials to the project area. Fossil fuels are combusted for the operation of mobile combustion equipment used for demolition and earthwork to prepare the site. In addition, indirect GHG emissions result from production of the materials required for construction of the Proposed Action, such as conveyors, roadways, docks, and berms. Table 17 summarizes the required equipment and duration of use.

Table 17. Major Construction Activities and Typical Equipment Fleets[a]

Construction Equipment Type	Rail Infrastructure and Rotary Car Dump Station		Conveyors, Transfer Stations and Surge Bins		Shiploader, Dock, and Trestles	
	Max Qty. per Month	Duration (months)	Max Qty. per Month	Duration (months)	Max Qty. per Month	Duration (months)
Mobile cranes (25–50 ton)	2	18	2	18	2	18
Mobile cranes (50–150 ton)	2	18	2	18	2	18
Mobile cranes (150–300 ton)	1	18	1	18	1	18
Water trucks	1	12	1	12	0	0
Dump trucks	3	12	1	12	0	0
Dozers	1	5	0	0	0	0
Excavators	1	9	2	12	1	3
Rollers	2	9	2	12	1	3
Graders	2	9	0	0	1	3
Compactors	2	9	2	12	1	3
Track laying machine	1	2	0	0	0	0
Drill rigs	1	2	2	6	0	0
Impact piling rigs	2	6	2	6	2	6
Loaders	1	12	1	12	1	9
River barge	0	0	0	0	2	18
Generator	2	18	2	18	2	18
Air compressor	2	18	2	18	2	18

Notes:
[a] Typical construction fleet may be modified with equivalent items as construction activities demand.
Sources: URS Corporation 2014b, ICF 2017b

Combustion emissions estimates are obtained from the NONROAD emissions model (U.S. Environmental Protection Agency 2009a) for the nonroad equipment. Construction activity is assumed to occur 8 hours per day, 5 days a week, 52 weeks per year, with the exception of the track-laying machine, which operates 4 hours per day. Emission factors are applied to the maximum numbers of equipment operated, duration of use, and horsepower, to obtain annual emissions.

Table 18 provides information on the emission factors for construction equipment.

Table 18. Construction Equipment Activity Data and Emission Factors

Equipment Type	Engine Size	Fuel Type	Number of Equipment Units	Emission Factor ($MtCO_2e$/year per Unit)[c]
Crane, 50-ton	165	Diesel	2	109.3
Crane, 150-ton	280	Diesel	2	183.0
Crane, 300-ton	450	Diesel	1	195.4
Water trucks	350	Diesel	1	98.8
Dump trucks	350	Diesel	4	98.8
Dozers	185	Diesel	0.4	396.5
Excavators	230	Diesel	2	886.6
Rollers	350	Diesel	3.8	100.3
Graders	185	Diesel	1.8	132.7
Compactors	25	Diesel	3.8	0.2
Track laying machine	[a]	Diesel	0.5	416.8
Drill Rigs	(NONROAD Default)[b]	Diesel	1.2	57.1
Impact Piling Rigs	(NONROAD Default)[b]	Diesel	3	57.1
Loaders	140	Diesel	1	416.8
Generator	30	Diesel	6	108.8
Air Compressor	25	Diesel	6	0.3

Notes:

[a] Assumes track-laying machine uses one diesel locomotive and one front end loader engine. Assumes full-time locomotive used 4 hours/day, 5 days/week.

[b] Horsepower and weight estimates are based on capacity ratings and industry specifications, or average ratings per equipment type. Where horsepower could not be assumed, an average horsepower rate in NONROAD for the equipment type is used.

[c] To calculate annual emissions, this emission factor is multiplied by 1.5 years to estimate the emissions for 18 months of construction.

Source: ICF 2017b

$MtCO_2e$ = metric tons of carbon dioxide equivalent

The impact of construction employee commuting is calculated using the MOVES model (U.S. Environmental Protection Agency 2014a), assuming that construction workers would use single-occupant vehicles with a mean round-trip travel time of 48.2 minutes. The analysis assumes that the 200 workers would be commuting during construction. At an estimated speed of 35 miles per hour, this amounts to 1,462,067 miles per year travelled. This distance is multiplied by emission factors for typical commuting vehicles provided by the MOVES model to calculate annual emissions.[26]

For the construction barges (operating under their own power or pushed/towed by another vessel), emissions are calculated using the EPA's AP-42 method for large diesel engines (U.S. Environmental Protection Agency 1996). The analysis assumes that the construction barges would have a positioning time of 1 hour with 1 round trip per day, 5 days per week, 52 weeks per year. Summaries of the barge activity and emission factors are available in Table 19 and Table 20, respectively.

[26] The analysis assumes a 50/50 mix of gasoline and E-85 for construction employee commuting vehicles.

Table 19. Barge Activity and Energy Use for Coal Export Terminal Construction

Barge Activity	Energy Consumption Variables
Barges used	2
Engine size (propulsion)	3,500 hp
Positioning time	1 hour
Total power per trip	7,000 hp
Construction trips	260 trips per year
Annual power	1,820,000 MMBtu per year

Source: ICF 2017b
hp = horsepower; MMBtu= million British thermal units per year

Table 20. Emission Factors for Construction Barges

Greenhouse Gas	$kgCO_2e$ per MMBtu	Emission Factor ($MtCO_2e$/ 1,000 gallons)
Carbon dioxide	74.8	10.23
Methane	0.1	0.1
Nitrous oxide	0.1	0.1
Total	75.0	10.25

Source: U.S. Environmental Protection Agency 1996
$kgCO_2e$ = kilograms of carbon dioxide equivalent; MMBtu = million British thermal units; $MtCO_2e$ = metric tons of carbon dioxide equivalent

The project area does not have an existing barge dock. Therefore, the material from incoming barges would be off-loaded at an existing dock elsewhere on the Columbia River and transported to the project area by truck. Emissions from trucks hauling construction material to the project area are estimated by determining the annual miles traveled by trucks going to and from the construction site and then multiplying those miles traveled by a per-mile emission factor from EPA's MOVES model. The peak annual trips for the Proposed Action are assumed 56,000 round trips (88,000 throughout the entire construction period) (URS Corporation 2015). Short-haul combination tractor-trailer trucks are assumed to move construction material with 47 roundtrip miles of travel in the county. The GHG emission factor is from a MOVES model run for Cowlitz County for the year 2018 (i.e., 1,561 to 1,930 grams of CO_2e per mile, depending on operating conditions).

The GHG emission assessment of the Proposed Action also includes an analysis of the emissions associated with the production of materials used in the initial construction of the coal export terminal. Production of materials, for the purpose of this analysis, includes raw materials extraction and processing, and product manufacturing. Transportation requirements are included for all supply chain elements up to the point of product manufacturing. The transportation of products from the manufacturer to the project area is modeled separately, as described in the previous paragraph.

The GHG emissions associated with construction materials for the Proposed Action are estimated using primary data from coal export terminal facility designs from the Applicant for total estimated material mass. Table 21 presents the estimated material masses for the coal export terminal by general type of material (e.g., concrete, steel, aggregate, and asphalt). The material masses are applied to the most recent and relevant emission factors for manufacturing of each material type. Table 21 summarizes these emission factors, modeling sources, and specific assessment notes or assumptions.

Table 21. Terminal Material Mass and Emission Factors

Facility Material/ Application	Mass (Mt)[a]	Emission Factor Material(s) Assumed	Emission Factor (kg CO_2e/Mt)	Emission Factor Source
Concrete	410,000	Concrete	180.3	UC Berkeley 2016
Berm Import Material	730,000	Primarily aggregates, assumed to be limestone gravel	3.9	Wernet et al. 2016
Transfer towers, galleries, etc.				
Structural Steel	9,500	Low-alloy steel	799.8	Wernet et al. 2016
Steel Piles	6,900	Low-alloy steel	799.8	Wernet et al. 2016
Rebar	9,300	Reinforcing steel	2,361.2	Wernet et al. 2016
Miscellaneous Steel	1,900	Low-alloy steel	799.8	Wernet et al. 2016
Rail System				
Rail	1,600	Steel	3,100.0	Hill et al. 2011
Gravel Ballast	57,600	Aggregate	8.0	Hill et al. 2011
Concrete Ties	9,800	Concrete	180.3	UC Berkeley 2016
Conveyors				
Idlers, belts, drives, take-up, stringers	8,300	Low-alloy steel	799.8	Wernet et al. 2016
Bridge Structures[b]				
Concrete	8,190	Concrete	180.3	UC Berkeley 2016
Rebar	910	Reinforcing steel	2,361.2	Wernet et al. 2016
Roadways[c]				
Asphalt	18,050	Asphalt	91.1	EIO-LCA: 2002 Purchaser (CMU GDI 2008)
Aggregate	11,950	Limestone gravel	3.9	Wernet et al. 2016
Buildings (Administration & Maintenance)	200	Assumed to be made up of low-alloy steel (33.3% of mass) and reinforced concrete (66.6%)	532.2	Wernet et al. 2016 , UC Berkeley 2016
Piping/Utilities	500	Ethylene pipeline	1,509.2	Wernet et al. 2016
Miscellaneous pumps, precast concrete, etc.	250	Assumed to be made up of low-alloy steel (33.3% of mass) and reinforced concrete (66.6%)	532.2	Wernet et al. 2016, UC Berkeley 2016
Electrical				
Substation	100	Low-alloy steel	799.8	Wernet et al. 2016
MCC Buildings	125	Assumed to be made up of steel (33.3% of mass) and reinforced concrete (66.6%)	799.8	Wernet et al. 2016, UC Berkeley 2016
Conduit, cable tray, cable, etc.	700	General cable	4,923.8	Wernet et al. 2016

Facility Material/ Application	Mass (Mt)[a]	Emission Factor Material(s) Assumed	Emission Factor (kg CO_2e/Mt)	Emission Factor Source
Major Equipment				
Tandem Rotary Dumper	500	Low-alloy steel	799.8	Wernet et al. 2016
Stackers	1,875	Low-alloy steel	799.8	Wernet et al. 2016
Reclaimers	3,300	Low-alloy steel	799.8	Wernet et al. 2016
Trestle/Dock/ Shiploaders				
Concrete	36,300	Concrete	180.3	UC Berkeley 2016
Rebar	900	Reinforcing steel	2,361.2	Wernet et al. 2016
Steel Piles	20,000	Low-alloy steel	799.8	Wernet et al. 2016
Shiploaders	3,300	Low-alloy steel	799.8	Wernet et al. 2016
10% Miscellaneous	135,200	Estimated material type, mass, and emission factor based on distribution of known materials	121.8	Emission factor based on distribution of known materials

Notes:

[a] Source: Millennium Bulk Terminals-Longview 2016, Hill et al. 2011, Wernet et al. 2016, UC Berkeley 2016

[b] Structures made of reinforced concrete. Assumed 90% of mass from concrete, 10% steel rebar.

[c] Roadways are designed with 3" of pavement (asphalt), 3" of subgrade (aggregate). Assumed a road width of 32" based on Cowlitz County (2007) standards.

Mt = metric tons of material; kgCO_2e/Mt = kilograms of carbon dioxide equivalent per metric ton of material

Construction of the coal export terminal would require dredging a 48-acre area (an estimated 500,000 cubic yards of sediment) of the river bottom to provide berthing at Docks 2 and 3. Emissions from equipment use for dock dredging were estimated by first determining the equipment necessary for typical dredging operations. Assumptions on the number of tugboats were based on a similar dredging analysis for the Port of Long Beach (Port of Long Beach 2012), while the dredge was assumed to be a diesel clamshell dredge with a capacity of 1,800 cubic yards per hour (Gaines pers. comm.). Horsepower assumptions were used from a similar dredging analysis performed for the Puget Sound Maritime Air Forum (Puget Sound Maritime Air Forum 2012) for tugboat engines, and Ellicott Dredges 2016 for the diesel dredge engines to estimate annual exhaust emissions from dredging equipment use (Table 22). The estimated 500,000 cubic yards of sediment were used to determine the number of tugboat trips required to transport dredged sediment, where 1 hour per round trip was assumed for transporting dredged material for a maximum distance of 3 miles back and forth along the Columbia River (Millennium Bulk Terminal—Longview 2014). The number of trips along the Columbia River was determined by the barge capacity of 2,250 cubic yards (Gaines pers. comm.). Based on these activities and the emission factor for diesel use of 692 g CO_2e/kWh (California Air Resources Board 2011), an annual emission factor for equipment was calculated as provided in Table 22.

Table 22. Coal Export Terminal Equipment and Emission Factors – Dredging Equipment

Equipment Type	Engine Size	Fuel Type	Emission Factor ($MtCO_2e$/year)[a]	Data Sources
Tugboat (Propulsion)	1,506 hp	Diesel	42.8	Puget Sound Maritime Air Forum 2012
Tugboat (Auxiliary)	125 hp	Diesel	3.1	Puget Sound Maritime Air Forum 2012
Tugboat aux at berth	125 hp	Diesel	1.0	Puget Sound Maritime Air Forum 2012
Diesel hydraulic dredge	2,680 hp	Diesel	98.0	Ellicott Dredges 2016, California Air Resources Board 2016
Auxiliary engine for hydraulic dredge	1,410 hp	Diesel	43.5	Ellicott Dredges 2016, California Air Resources Board 2016

$MtCO_2e$ = metric tons of carbon dioxide equivalent; hp = horsepower

[a] Calculated based on duration of 2 years for dredging activities to remove a total of 500,000 cubic yards of sediment, and engine horsepower and load factors as provided in Puget Sound Maritime Air Forum 2012, Ellicott Dredges 2016, California Air Resources Board 2016, and a diesel emission factor from California Air Resources Board 2011.

Coal Export Terminal Operation—Equipment Operation

Direct sources of GHG emissions from equipment operation at the terminal include fossil fuel emissions from mobile equipment on land, mobile equipment for maintenance dock dredging, and emergency equipment. Examples of equipment used for coal export terminal operation include loaders, maintenance vehicles, cranes, and emergency water pump and generator equipment. This equipment uses diesel, gasoline, and propane fuels. Emissions from mobile combustion sources and emergency equipment are estimated by first determining the equipment necessary for typical operation and maintenance and then using the NONROAD model (U.S. Environmental Protection Agency 2009a) to estimate annual exhaust emissions from that mobile and emergency equipment (Table 23). In addition to removing 500,000 cubic yards during construction, annual maintenance dredging of up to 100,000 cubic yards would occur during operation of the coal export terminal. Greenhouse gas emissions are estimated using the same method used during construction and the resulting emission factors are presented in Table 24.

Table 23. Coal Export Terminal Equipment and Emission Factors – Mobile Combustion and Emergency Equipment

Equipment Type	Engine Size	Fuel Type	Number of Equipment Units[a]	Emission Factor ($MtCO_2e$/year per Unit)[b]
Loader	300 hp	Diesel	1	671.7
Bobcat	50 hp	Diesel	2	16.6
10-Ton Truck	300 hp	Diesel	2	98.8
Crane	50 hp	Diesel	1	0.0
Forklift	40 hp	Propane	1	0.1
Maintenance Trucks	300 hp	Gasoline	4	0.2
Fire Water Pump	200 hp	Diesel	1	3.5
Emergency Generators	30 hp	Diesel	2	0.5

Source: U.S. Environmental Protection Agency 2009a, U.S. Environmental Protection Agency 2016c

[a] An equipment unit represents the number of equipment types are that are used in a year for annual operations. Hours of operation are based on those specified in the SEPA Air Quality Technical Report (ICF 2017b).

[b]-Calculated based on horsepower and hours of operation assumptions used in the SEPA Air Quality Technical Report (ICF 2017b).

$MtCO_2e$ = metric tons of carbon dioxide equivalent; hp = horsepower

Table 24. Coal Export Terminal Equipment and Emission Factors – Maintenance Dredging

Equipment Type	Engine Size	Fuel Type	Emission Factor ($MtCO_2e$/year)[b]	Data Source
Tugboat (Propulsion)	1,506 hp	Diesel	17.1	Puget Sound Maritime Air Forum 2012
Tugboat (Auxiliary)	125 hp	Diesel	1.2	Puget Sound Maritime Air Forum 2012
Tugboat aux at berth	125 hp	Diesel	0.4	Puget Sound Maritime Air Forum 2012
Diesel hydraulic dredge	2,680 hp	Diesel	39.2	Ellicott Dredges 2016, California Air Resources Board, 2016
Auxiliary engine for hydraulic dredge	1,410 hp	Diesel	17.4	Ellicott Dredges 2016, California Air Resources Board, 2016

$MtCO_2e$ = metric tons of carbon dioxide equivalent; hp = horsepower

[b] –Calculated based on engine size, emission factor for diesel, and equipment use for one year of operation dredging 100,000 cubic yards of sediment.

Coal Export Terminal Operation—Electricity Consumption

Indirect sources of GHG emissions for electrical consumption include fuel combustion emissions at off-site power plants to produce electricity consumed at the coal export terminal. The local energy grid would provide electricity for operation of coal export terminal facilities. The additional electricity consumption that would be required for the coal export terminal is assumed similar to the annual energy use for the existing bulk product terminal (Chany pers. comm.). To estimate net annual increase in GHG emissions from electricity consumption, the monthly electricity demand for the existing bulk product terminal is annualized in kilowatt-hours, as shown in Table 25.

Table 25. Monthly and Annual Electricity Demand for Coal Export Terminal

Time Period	Usage
Monthly	552,000 kWh
Annual	6,624 MWh

Notes:
Additional demand is assumed to occur throughout the entire analysis period, including construction.
Source: Chany pers. comm.
kWh = kilowatt hour; MWh = megawatt hour

To derive additional GHG emissions from electricity consumption for coal export terminal operations, the electricity fuel mix for an average water year is obtained from the Cowlitz Public Utility District. Emission factors for each fuel type are then derived from individual plant data for each fuel in the Western Electricity Coordinating Council Northwest subregion as provided in the Emissions & Generation Resource Integrated Database (eGRID). These individual fuel emission factors are combined using the Cowlitz Public Utility District fuel mix to obtain a weighted average emission factor to apply to electricity consumption from the Proposed Action. Table 26 provides the fuel mix and emission factors used to derive GHG emissions from electricity consumption for coal export terminal operations.

Table 26. Average Fuel Mix and Fuel-Specific Emission Factor for the Cowlitz Public Utilities District Region

Fuel Source	Share of Electricity Fuel Mix (%)	Carbon Dioxide (kg CO_2e/MWh)	Methane (kg CO_2e/MWh)	Nitrous Oxide (kg CO_2e/MWh)	Total (kg CO_2e/MWh)
Hydro	84.64%	0	0	0	0
Nuclear	9.70%	0	0	0	0
Wind	2.66%	0	0	0	0
Coal	2.08%	1,095.8	0.3	5.5	1,101.5
Natural Gas	0.79%	436.8	0.2	0.3	437.3
Other[a]	0.13%	302.0	0.1	1.4	303.5
Weighted Average	**100%**	**26.6**	**0.01**	**0.1**	**26.8**

[a] Other is made up of biomass, cogeneration, geothermal, landfill gas, petroleum, solar, and waste incineration.
Source: Cowlitz Public Utility District 2015, U.S. Environmental Protection Agency 2015b

Employee Commuting

Direct sources of GHG emissions from employee commuting include the emissions from fossil fuel combustion associated with the daily commuting traffic for employees to and from the site. The GHG emissions from employees commuting to the project area are calculated using the MOVES model (U.S. Environmental Protection Agency 2014a), assuming that employees would use single-occupant vehicles with a mean round-trip travel time of 48.2 minutes. The analysis assumes that there are 135 employees, with 25 commuting 5 days per week and 110 commuting 7 days per week. At an estimated speed of 35 miles per hour, this amounts to 1,092,051 miles per year travelled. This distance is multiplied by emission factors for typical commuting vehicles provided by the MOVES model to calculate annual emissions.[27]

Vessel Idling and Tugboat Use at Coal Export Terminal

Direct sources of GHG emissions from vessel idling and tugboat use at the coal export terminal include current vessel operations at the coal export terminal, as vessels use main and auxiliary motors to maneuver in and out of the loading area. Additionally, this source includes fossil fuel combustion emissions from tugboats that are used to assist in vessel maneuvering at the project area.

GHG emissions from vessel idling and tugboat use are calculated by estimating the power consumed by idling vessels, converting the power demand into fuel consumption, and multiplying that fuel consumption by a fuel combustion emission factor. An average of 13 hours would be needed to load each vessel with coal, and during this period, the vessel would be hoteling using auxiliary engines. For each vessel, the typical main and auxiliary engine size is based on Lloyd's Register of Ships Sea-web, which has a database of ship characteristics for ships over 100 gross tons (Sea-web 2015). Each vessel receiving coal is assumed to need three tugs to maneuver the ship. These tugs would operate for 3 hours to assist with docking and departing. The time spent operating the vessels in each mode, multiplied by the estimated engine load and size provided power demand for both the idling vessels and tugboats. The power demand is then multiplied by the emission factors provided in Table 27.

Table 27. Emission Factors for Idling Vessels and Tugboats

Greenhouse Gas	Main Engine Emission Factor (g CO_2e per kWh)	Auxiliary Engine Emission Factor (g CO_2e per kWh)
Carbon dioxide	588	690
Methane	1.75	2.25
Nitrous oxide	0.12	0.12
Total	**590**	**692**

Source: California Air Resources Board 2011. *Appendix D: Emissions Estimation Methodology for Ocean-Going Vessels.*
gCO_2e = grams of carbon dioxide equivalent; kWh = kilowatt-hour

Helicopter and Pilot Boat Trips

Indirect sources of GHG emissions for helicopter and pilot boat transfers include fossil fuels burned to pilot vessels along the Columbia River. GHG emissions from helicopter and pilot boat trips that transfer pilots to vessels are calculated as described in the SEPA Vessel Transportation Technical Report (ICF 2017e). The trips for both vehicle types are multiplied by the distance for each trip to derive the total mileage and fuel consumption for each trip. Assuming that at full capacity, the Proposed Action would service 840 vessels annually and each vessel would require piloting in and out of the Columbia River Bar, this use equates to 1,680 pilot transfers per year. Incoming and outgoing vessels are piloted 15 nautical miles (17 standard miles) from the mouth of the Columbia River, for an average distance of 30 nautical miles (34 standard miles) per trip. The bar pilot to river

[27] The analysis assumes a 50/50 mix of gasoline and E-85 for employee commuting vehicles.

pilot changeover takes place at Tongue Point near Astoria for both outbound and inbound vessels, therefore only one pilot transfer is needed for each incoming and outgoing vessel (Ellenwood pers. comm.). Helicopters are used for offshore transfer of Columbia River Bar pilots 70% of the time, with the remaining 30% of the offshore transfers conducted using a pilot boat due to more challenging weather conditions (Table 28).

Table 28. Annual Helicopter and Pilot Boat Transfers per Vessel, 2028

Project Year	Total Number of Vessels Traveling to the Coal Export Terminal	Number of Pilot Transfers		Total Number of Pilot Transfers
		Helicopter	Pilot Boat	All
2028	840	1,176	504	1,680
Source: ICF 2017e, Ellenwood pers. comm.				

The trips are multiplied by the distance to estimate the total nautical miles travelled per mode of transport, as shown in Table 29.

Table 29. Helicopter and Pilot Boat Trips and Nautical Miles Travelled

Project Year	Helicopter		Pilot Boat	
	Trips	Total Miles	Trips	Total Miles
2028	1,176	40,600	504	17,400
Source: ICF 2017e				

GHG emissions from each mode of transport are based on the time of travel from shore to the vessels. The average trip time for helicopters is assumed 18 minutes (Ellenwood pers. comm.). For pilot boats, an average speed of 14 miles per hour is assumed (Columbia River Bar Pilots 2015), resulting in a roundtrip travel time of 2.5 hours. For helicopters, the fuel consumption rate of 1 gallon per minute was obtained directly from Brim Aviation (Ellenwood pers. comm.). Fuel consumption and aviation gasoline emission factors are presented in Table 30 and Table 31, respectively. The emissions are calculated by first estimating the amount of fuel consumed per helicopter trip, multiplying that by the emission factor for aviation gasoline, and then by the number of helicopter trips.

Table 30. Helicopter Fuel Consumption

Aircraft	Average Fuel Consumption Rate (Gallons per Minute)	Average Trip Time (Minutes)
Sikorsky S-76 "Seahawk"	1	18

Source: Ellenwood pers. comm.

Table 31. Combustion Emissions for Aviation Gasoline

Greenhouse Gas	Emission Factor ($MTCO_2e$/1,000 gallons)
Carbon dioxide	8.31
Methane	0.18
Nitrous oxide	0.03
Total	**8.52**

Source: U.S. Environmental Protection Agency 2015a
$MTCO_2e$ = metric tons of carbon dioxide equivalent

GHG emissions from pilot boats are based on the energy required for the pilot boat to make one trip based on the estimated round-trip duration of 2.5 hours. Energy is converted into gallons of residual fuel and multiplied by an emission factor for residual fuel combustion in order to calculate the GHG emissions for a single pilot boat trip. This value is then multiplied by the total number of annual pilot boat trips to estimate the total annual GHG emissions. The factors used to estimate the energy consumption and the emissions for pilot boats are shown in Table 32 and Table 33, respectively.

Table 32. Factors for Pilot Boat Fuel Consumption

Factor	Magnitude
Trip duration	2.5 hours
Horsepower of engines[a]	1,800 hp
Average engine load over trip[b]	45%
Energy consumed, kWh	1,511 kWh
Energy consumed, MMBtu[c]	5.2 MMBtu
Energy in residual fuel[d]	0.15 MMBtu per gallon
Gallons of residual fuel consumed	34.4 gallons per trip

Notes:
[a] Brusco Tug and Barge Undated
[b] California Air Resources Board 2011
[c] Estimated by converting kWh to MMBtu
[d] U.S. Environmental Protection Agency 2015a
hp = horsepower; MMBtu = million British thermal units

Table 33. Combustion Emissions for Residual Fuel

Greenhouse Gas	Emission Factor ($MtCO_2e$/1,000 gallons)
Carbon dioxide	11.24
Methane	0.003
Nitrous oxide	0.17
Total	**11.41**

Source: U.S. Environmental Protection Agency 2015a
$MTCO_2e$ = metric tons of carbon dioxide equivalent

Vessel Transport

Vessel transport is calculated in three phases: the transport of coal between the project area and the border of Cowlitz County, the transport of coal down the Columbia River through Washington State, and lastly, the transport of coal to markets in Asia. Both incoming and outgoing vessel traffic are accounted for within Cowlitz County and Washington State, while only a share of the returning vessels from Asia are accounted for since only a share of these vessels return with ballast water only.

Vessel Transport in Cowlitz County

Direct sources of GHG emissions from vessel transport in Cowlitz County include fossil fuel combustion associated with current vessel transport from the coal export terminal down the Columbia River to the border of Cowlitz County, a 9.87 nautical mile (11.35 mile) distance. This distance is repeated to account for empty vessels returning to the coal export terminal. GHG emissions from vessel transport are calculated using the same method as for air emissions and summarized in the SEPA Air Quality Technical Report (2017b). This analysis assumes that the coal export terminal would be serviced by a mix of Panamax (80%) and Handymax (20%) vessels. To incorporate this assumption, the engine size is considered a weighted average of Panamax and Handymax vessels. For each vessel, the typical main and auxiliary engine size is based on Lloyd's Register of Ships Sea-web, which has a database of ship characteristics for ships over 100 gross tons (Sea-web 2015).

GHG emissions from vessel idling and tugboat use are calculated by estimating the energy consumed by vessels exiting Cowlitz County, which is a factor of the duration to enter or exit the county, the engine size, and engine load for loaded ships in transit. The annual energy demand is multiplied by an emission factor for main engine vessel use for loaded transit. The one-way transit time within Cowlitz County is assumed 0.9 hour. The annual energy demand is then multiplied by the emission factors provided in Table 34.

Table 34. Emission Factors for Vessels in Transit

Greenhouse Gas	Main Engine Emission Factor (g CO_2e per kWh)	Auxiliary Engine Emission Factor (g CO_2e per kWh)
Carbon dioxide	588	690
Methane	1.75	2.25
Nitrous oxide	0.12	0.12
Total	**590**	**692**

Source: California Air Resources Board 2011. *Appendix D: Emissions Estimation Methodology for Ocean-Going Vessels.*
$kgCO_2e$ = kilograms of carbon dioxide equivalent; kWh = kilowatt-hours

Vessel Transport in Washington State beyond Cowlitz County

As previously mentioned, the coal export terminal would be serviced by a mix of Panamax (80%) and Handymax (20%) bulk carrier vessels. To incorporate this assumption for vessel transport outside of Cowlitz County through Washington State and overseas to Asian markets, IHS Sea-Web data (Sea-web 2015), a database of ship characteristics for ships over 100 gross tons, is used to determine average service speed and total propulsion power for the two vessels. Four vessels for each size are used with the same approximate deadweight tons of the two vessels to determine the averages. Ship characteristics for the two vessels are shown in Table 35.

Table 35. Average Vessel Characteristics

Vessel Size	Main Engine Propulsion Power (kW)	Average Vessel Service Speed (knots)
HandyMax	7,789	14.40
PanaMax	9,473	14.39

Source: Sea-web 2015

Emissions are estimated depending upon operating mode. Three operating modes are defined here, namely, open-ocean, transit down the Columbia and hoteling at berth. Movement in the open-ocean between the mouth of the Columbia River and Asia occurs at service speed. Transit down the Columbia River occurs at 8.4 knots (average between 6.5 knots up and 12 knots down the Columbia River due to currents) (Breen pers. comm.).

Propulsion engine load factors are determined using the propeller law, which is the cube of the actual vessel speed divided by the maximum vessel speed. Service speed is typically 93.5% of maximum speed (ICF 2009). Auxiliary engine and boiler loads are from the 2014 Port of Los Angeles Emissions Inventory Document and are listed in Table 36 (Starcrest Consulting Group 2015). When the propulsion engines are operating at 20% load or more, exhaust economizers supply steam so boilers are shut off.

Table 36. Auxiliary Engine and Boiler loads

Operation	Loads (kW) Auxiliary	Boiler
Moving	225	132

Source: Starcrest Consulting Group 2015
kW = kilowatt

Emission factors in grams per kilowatt-hour from the California Air Resources Board are used to develop overall ship emission factors in terms of kilograms per nautical mile. Table 37 presents emission factors in grams per kilowatt-hour for each greenhouse gas.

Table 38 presents the overall ship emission factors in kg per nautical mile based on the various speed and load assumptions for the two ships.

Table 37. Vessel Emission Factors by Equipment Type

Greenhouse Gas	Main Engine Emission Factor (g CO_2e per kWh)	Auxiliary Engine Emission Factor (g CO_2e per kWh)	Boiler Emission Factor (g CO_2e per kWh)
Carbon dioxide	588	690	970
Methane	1.75	2.25	0.75
Nitrous oxide	0.12	0.12	0.12
Total	590	692	971

Source: California Air Resources Board 2011. *Appendix D: Emissions Estimation Methodology for Ocean-Going Vessels.*
kgCO_2e = kilograms of carbon dioxide equivalent; kWh = kilowatt-hours

Table 38. Emission Factors by Vessel Type

Ship	CO_2e emission factors (kg/nm) At Sea	Columbia
HandyMax	277.69	124.28
PanaMax	335.59	144.14

Source: Calculated.
kg/nm = kilograms per nautical mile

Indirect sources of GHG emissions from vessel transport outside of Cowlitz County but within Washington State include fossil fuel combustion. This analysis assumes a distance of 47.78 nautical miles (54.94 miles), which takes the vessels from the border of Cowlitz County to 3 nautical miles past the mouth of the Columbia River. This distance is repeated for vessels returning to the state to pick up coal. Emissions are calculated by multiplying this distance by the Columbia River emission factor.

Vessel Transport to Asian Markets

Indirect sources of GHG emissions from vessel transport to Asian markets include fossil fuel combustion. GHG emissions are based on nautical miles of shipping from the coal market assessment, which provides yearly total nautical miles of coal shipped throughout the Pacific Basin for both the action and no-action models for each scenario. The difference in ship traffic between these scenarios is used to estimate the change in nautical miles attributable to the Proposed Action. Table 39 summarizes the distances to Asian markets from the United States.

For changes in coal shipments within the Pacific Basin, GHG emissions are based on an estimate in the coal market assessment of the total net change in nautical miles traveled within the Pacific Basin. This estimate considers the total change in Pacific Basin coal traffic because of the Proposed Action, including the new coal coming from the United States, and shifts in coal shipments from producers primarily in Indonesia, Australia, Russia, and China.

Table 39. Net Change in Nautical Miles Traveled by Proposed Action-Related Vessels

Scenario	2020	2025	2030	2040
2015 U.S. and International Energy Policy	0	2,722,792	2,525,104	3,145,596
Lower Bound	0	3,459,178	2,524,928	3,176,780
Upper Bound	0	3,324,926	2,555,506	3,721,348
No Clean Power Plan	0	2,086,181	2,591,077	2,311,512
Cumulative	0	5,805,597	7,365,846	8,235,972

Notes: 1 nautical mile is equivalent to 1.15078 miles. The net change in nautical miles includes vessels departing from the terminal, and vessels that would be substituted by vessels departing from the terminal. The distances provided in this table are one-way distances.
Source: ICF 2017c

The total change in nautical miles traveled in the Pacific Basin from the Proposed Action is multiplied by the At Sea emission factor as provided in Table 38. The net impact of this emission source is the sum of the new emissions (delivery of coal from the Proposed Action) to Asian markets and the emissions offset from changes in Pacific Basin coal transport. In addition to the five Asian markets importing coal as identified in the coal market assessment, the effect of the Proposed Action on coal markets could cause shifts in additional Asian markets as Australian and Indonesian coals find new markets. The additional countries include India and other smaller consumers in the Pacific Basin that are grouped into the "Asia Other" demand region.[28] For example, for some scenarios, the coal market analysis indicates that Hong Kong substitutes some of its consumption of Indonesian coal with coal exported from the Proposed Action; however, the Asia Other demand region increases its purchases of the Indonesian coal displaced from Japan.

With few exceptions, dry bulk vessels "do not travel repetitive routes" and "dry bulk carriers seldom operate on round-trip voyages; the norm is multi-leg or triangular service to avoid excessive ballasting (traveling without paying cargo)" (Coal Age 2015). To estimate the share of trips that return empty and filled with ballast water, an analysis of data from the Automatic Identified System (AIS) from 2016 was performed.[29] The dataset was filtered to account for vessels that had the vessel type description of Handymax/Panamax. The percent of similar vessels that leave Asia in ballast is based on an evaluation of Automatic Identified System data to determine vessels of a similar size and class that transit near the mouth of the Columbia River and travel to/from Asia, and to conduct comparative data analysis of scantling and design draft of the individual vessels with the actual reported draft for each voyage. Based on this method, a conservative estimate of 40% of trips returning from Asia empty filled with ballast water was used. The same 40% is added onto

[28] This category includes Malaysia, the Philippines, Thailand, and Vietnam, as well as smaller importers of coal.
[29] An overview of the Automated Identified System is available from U.S. Department of Homeland Security, 2014.

international vessel transport from non-U.S. coal exports (e.g., Australia, Indonesia, Russia, and China) being substituted by the Proposed Action.

Coal Combustion in Asia and the United States

Indirect sources of GHG emissions from coal combustion include the change in both U.S. and Asia coal consumption that would result from a new coal export terminal. The coal market assessment estimates net coal combustion in Asia and the United States. These estimates are presented in the GHG analysis for each scenario relative to the no-action model results.

GHG emissions from coal combustion include those associated with market effects, which dictate the total amount of coal produced and combusted in the United States and Asia in response to coal supply and price. Emissions also reflect coal substitution, which is driven by the difference in carbon content between Powder River Basin coal, Uinta Basin coal, and coals produced in Asia. Table 40 summarizes the differences in carbon and heat contents among some of the coals assessed in the coal market assessment. [30]

Table 40. Heat Content and Carbon Coefficients for U.S. and Asian Reference Coals

Source	Coal Type	Heat Content (MMBtu per ton)[a]	CO_2 Emission Factor (pounds per MMBtu)
Powder River Basin—WY	Subbituminous	17.6	209.4
Powder River Basin—MT	Subbituminous	18.64 / 17.08	213.8
Uinta—CO	Bituminous	22.22	208.4
Uinta—UT	Bituminous	22.56 / 24.06	205.6
Australia	Bituminous	21.6	206.0
Indonesia	Bituminous	23.43 / 20.33	203.7
Indonesia	Subbituminous	18.05 / 17.19 / 15.12	214.8
China	Bituminous	23.85	212.2
China	Lignite	14.04	218.5

[a] For some coal types, more than one heat content value is indicated, because multiple coal types are modeled that have the same CO_2 emissions factor.
Source: ICF 2017c
MMBtu = million metric British thermal units; CO_2 = carbon dioxide

Induced Natural Gas Consumption in the United States

Indirect sources of GHG emissions from induced natural gas consumption would result from changes in consumption as a function of changes in the coal market. As coal prices increase due to the increased demand by the project for coal to export, the United States' natural gas consumption is expected to increase.

The Proposed Action could result in supply and price shifts in the coal markets, which affect the consumption of natural gas in the United States. The coal market assessment describes the substitution of natural gas for coal and estimates the GHG emissions from induced natural gas

[30] See the SEPA Coal Market Assessment Technical Report, Section 4.2.13 for the carbon and heat content of all of the coal types modeled.

consumption in the United States. Depending on the scenario, natural gas consumption changes based on coal prices and U.S. coal consumption.

2.3 Existing Conditions

The existing environmental conditions related to GHG emissions in the study area are described in the sections that follow.

2.3.1 Applicant's Leased Area

The existing bulk product terminal in the Applicant's leased area draws electricity from the regional electricity grid, amounting to 552,000 kilowatt hours of electricity demand per month, or 6,624 megawatt hours of electricity annually (Chany pers. comm.). The emissions from this source are already occurring and would continue whether or not the coal export terminal is constructed. Electricity usage results in indirect emissions of approximately 177 metric tons of CO_2e annually, as estimated in Section 3.1.8, *Coal Export Terminal Operation—Electricity Consumption.*

The current vessel traffic at Dock 1 is six ships per year. Using the method described in Section 2.2.2.3, *Method for Impact Analysis,* under *Vessel Transport in Cowlitz County,* and assuming that the vessels are docking for approximately 13 hours per trip, maneuvering for 1 hour, and transiting within Cowlitz County for 0.9 hour each way, their operation emissions total 95 metric tons of CO_2e annually. Table 41 describes the current vessel transport activity at the project area. The current emissions from the project area for the Proposed Action are relatively small compared to the scale of emissions from the Proposed Action and are thus not taken into account when estimating the net emissions associated with the Proposed Action.

Table 41. Current Vessel Transport Activities in the Project Area

Transport Type	Transport Activity	Facility Activity
Handymax Class Vessel	6 ships per year	Ships currently deliver alumina over Dock 1; the cargo is temporarily stored and then shipped to Chelan County by train

Source: ICF and Hellerworx 2017, and ICF 2017e

2.3.2 Cowlitz County

Approximately 7 trains per day consisting of approximately 78 cars typically pass between the BNSF Spur and main line (ICF and Hellerworx 2017). Using the method described in Section 2.2.2.3, *Method for Impact Analysis,* under *Rail Transport of Coal in Cowlitz County,* and assuming that the trains haul 122.1 metric tons of material per rail car, use two locomotives, and travel 20.0 miles through Cowlitz County to and from the north on the main line and BNSF Spur, the annual emissions from those trains are currently 2,206 metric tons of CO_2e. Baseline traffic on the Reynolds Lead at the project area in Cowlitz County is about two trains per day. Assuming that the trains traveling on the Reynolds Lead also haul 122.1 metric tons of material per rail car, use one locomotive, and travel the approximately 5-mile length of the Reynolds Lead, the annual emissions from those trains are currently 79 metric tons of CO_2e. These totals include trains delivering grain as well as trains connecting to other port facilities.

2.3.3 Washington State

Washington State's total GHG emissions were 92.0 MMTCO_2e in 2012, the most recent year for which a GHG Inventory was conducted. Of that total, 42.5 MMTCO_2e (46.2%) are attributable to the transportation sector, and 12.1 MMTCO_2e (13.2%) are attributable to coal combustion in the electricity sector (Washington State Department of Ecology 2016).

Rail traffic in Washington is busy in areas, with some route segments seeing as many as 70 trains per day (ICF and Hellerworx 2017). Existing rail capacity provides passenger service as well as transport for a variety of goods. The rail network accommodates empty and full coal trains as well as intermodal, grain, and general manifest trains from both BNSF and UP. Similarly, existing vessel traffic along the Columbia River is heavy due to the amount of bulk cargo transported in the region. The gross tonnage of vessel traffic in a 1-year period (averaged from 2010 to 2014) is approximately 91 million gross short tons (ICF 2017e).

Chapter 3
Impacts

This chapter describes the potential GHG emissions that would result from construction and operation of the Proposed Action relative to the No-Action Alternative.

3.1 Proposed Action

The GHG emissions are presented in terms of the 2028 emissions and total net emissions over the 2018 through 2038 analysis period. The total net emissions are the sum of emissions for the entire analysis period, including construction beginning in 2018 and operation through 2038.

The results are presented by emission sources, which are described in Section 2.2.2.3, *Method for Impact Analysis*. The source emissions are then combined into an estimate of total net GHG emissions.

3.1.1 Upland and Wetland Land-Cover Change

The vegetation removal, soil disturbance, and wetland loss associated with construction of the coal export terminal would result in the loss of accumulated carbon stocks during construction, as well as the loss of ongoing carbon sequestration from the removed vegetation (resulting in net increases in emissions) and a reduction in carbon dioxide and methane emissions from permanently filled wetlands over the analysis period (2018 through 2038). Table 42 presents the estimated emissions associated with construction of the coal export terminal.

Table 42. Vegetation Removal, Soil Disturbance, and Wetland Loss Emissions ($MtCO_2e$)

Emission Source	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Emissions During 12-Months of Construction Period ($MtCO_2e$)	11,771	11,771	11,771	11,771
Annual Emissions, 2028 ($MtCO_2e$)	17	17	17	17
Total Emissions, 2018–2038 ($MtCO_2e$)	12,121	12,121	12,121	12,121

Notes:
Vegetation Removal, Soil Disturbance, and Wetland Loss emissions represent the total emissions resulting from the proposed project emission sources, including: (1) loss of accumulated carbon stocks during construction; (2) lost sequestration from removed vegetation that results in net increases in emissions; and (3) reduction in carbon dioxide and methane emissions from permanently filled wetlands.
$MtCO_2e$ = metric tons of carbon dioxide equivalent

For construction of the Proposed Action, carbon stock losses are estimated to be 11,771 metric tons of CO_2e and total (2018 through 2038) emissions are estimated to be 12,121 metric tons of CO_2e (which includes GHG emissions of 350 metric tons of CO_2e from lost sequestration/wetland emission reductions).

3.1.2 Dock Dredging During Terminal Construction and Operations—Sediment Carbon

Dock dredging during terminal construction and operations associated with the Proposed Action would result in the potential loss of sediment carbon. Table 43 presents the estimated emissions associated with the potential loss of sediment carbon from dock dredging during coal export terminal construction and operations associated with the Proposed Action.

Table 43. Potential Loss of Sediment Carbon from Dock Dredging ($MtCO_2e$)

Emission Source	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Emissions During 12-Months of Construction Period[a] ($MtCO_2e$)	1,919	1,919	1,919	1,919
Annual Emissions, 2028 ($MtCO_2e$)	768	768	768	768
Total Emissions, 2018–2038 ($MtCO_2e$)	17,654	17,654	17,654	17,654

Notes:

[a] Dredging during the construction period is expected to occur over two annual approved work periods to coincide with fish protection during the construction phase (Millennium Bulk Terminal—Longview 2014). One of the approved work periods is assumed to coincide with the first 12 months of construction period, while the second dredging event is assumed to occur within the following year. Therefore, emissions during the 12 months of construction period shown above are assumed to be half of the total emissions of 3,838 $MMTCO_2e$ during the entire construction period from 2018-2020.

$MtCO_2e$ = metric tons of carbon dioxide equivalent

For dock dredging during terminal construction associated with the Proposed Action from 2018 through 2020, the potential loss of sediment carbon is estimated to be 3,838 metric tons of CO_2e and total (2018 through 2038) potential losses are estimated to be 17,654 metric tons of CO_2e. The 768 metric tons of CO_2e in 2028 is the potential loss of sediment carbon during annual maintenance dredging.

3.1.3 Coal Extraction

Coal extraction emissions are assumed to occur throughout the analysis period based on the coal extraction scenarios described in the coal market assessment. Under the approach described in Section 2.2.2.3, *Method for Impact Analysis,* the net indirect coal extraction GHG emissions from the Proposed Action are calculated by applying the GHG emission factors for each source of indirect emissions to the mass of U.S. coal extraction that would be induced by the Proposed Action, covering the Powder River Basin, the Uinta Basin, and other U.S. coal regions. These GHG estimates are offset by changes in GHG emissions from competing coal extraction outside the United States, primarily in Australia, China, and Russia. From these annual estimates of net GHG emissions, the net indirect GHG emissions are calculated for coal extraction that would result from the Proposed Action from 2018 through 2038.

The net emissions from coal extraction vary across the four scenarios depending on the magnitude of the increase in coal extraction in the United States, the different U.S. extraction regions impacted by the Proposed Action, the magnitude of the decrease in international coal extraction, and the different international extraction regions impacted by the Proposed Action throughout the analysis period. Coal extraction emissions vary for coal extracted in regions within the United States and regions outside the United States due to differences in the energy needed for coal extraction by region and mine type, grid electricity emission factors, grid electricity production mix, and methane emitted from different mining basins and mine types (i.e., underground or surface mining). Table 44 below presents estimates based on the coal extraction results provided in the coal market assessment.

Table 44. Emissions from Coal Extraction ($MMTCO_2e$)

	Scenario			
Emission Source	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Powder River Basin ($MMTCO_2e$)				
Annual Emissions, 2028	1.37	1.22	1.46	1.31
Total Emissions, 2018-2038	17.97	17.60	21.91	18.65
Uinta Basin ($MMTCO_2e$)				
Annual Emissions, 2028	-0.04	0.02	0.22	<0.005
Total Emissions, 2018-2038	3.40	0.59	9.94	<0.005
Other U.S. Coals ($MMTCO_2e$)				
Annual Emissions, 2028	0.09	0.27	<0.005	<0.005
Total Emissions, 2018-2038	2.27	3.67	0.78	<0.005
Australia ($MMTCO_2e$)				
Annual Emissions, 2028	-0.39	-0.40	0	-1.22
Total Emissions, 2018-2038	-4.86	-4.89	0	-15.26
Canada ($MMTCO_2e$)				
Annual Emissions, 2028	0	<0.005	0	0
Total Emissions, 2018-2038	0	-0.01	0	0
China ($MMTCO_2e$)				
Annual Emissions, 2028	-2.56	-2.17	1.87	-2.74
Total Emissions, 2018-2038	-69.38	-60.63	23.09	-44.85
India ($MMTCO_2e$)				
Annual Emissions, 2028	0	-0.50	0	-0.28
Total Emissions, 2018-2038	0	-4.09	-4.64	-2.31
Indonesia ($MMTCO_2e$)				
Annual Emissions, 2028	-0.28	-0.04	-0.41	-0.27
Total Emissions, 2018-2038	-2.27	-0.31	-4.53	-3.17
Russia ($MMTCO_2e$)				
Annual Emissions, 2028	-3.15	-3.08	-1.65	<0.005
Total Emissions, 2018-2038	-33.33	-32.66	-20.39	-9.56
South Africa ($MMTCO_2e$)				
Annual Emissions, 2028	0.04	0	-0.41	<0.005
Total Emissions, 2018-2038	0.30	0	-5.09	<0.005
Net Emissions ($MMTCO_2e$)				
Annual Emissions, 2028	-4.91	-4.68	1.08	-3.21
Total Emissions, 2018-2038	-85.90	-80.74	21.07	-56.50

Notes: "Other U.S. Coals" includes the following basins: Central Appalachia (VA, WV, East KY), Illinois, Northern Appalachia, Rockies (Green River, San Juan, Raton), Warrior, North Great Plains (Non-Powder River Basin – WY, MT, ND), West Interior (Arkoma, Gulf Coast, Forest City, Cherokee)$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

Figure 7 presents the net GHG emissions from changes in coal extraction in each country between 2021-2038 for the 2015 U.S. and International Energy Policy scenario. Reduced GHG emissions in China have the largest impact on the net GHG emissions, as production is increasingly offset by greater PRB and Uinta coal production. The black bars in the Figure 7 indicate the resulting net GHG emissions from coal extraction. Figure 8 details net GHG emissions by country over time for each of the four scenarios.

Figure 7. Net GHG Emissions from Coal Extraction by Country and U.S. Coal Basin for 2015 U.S. and International Energy Policy Scenario

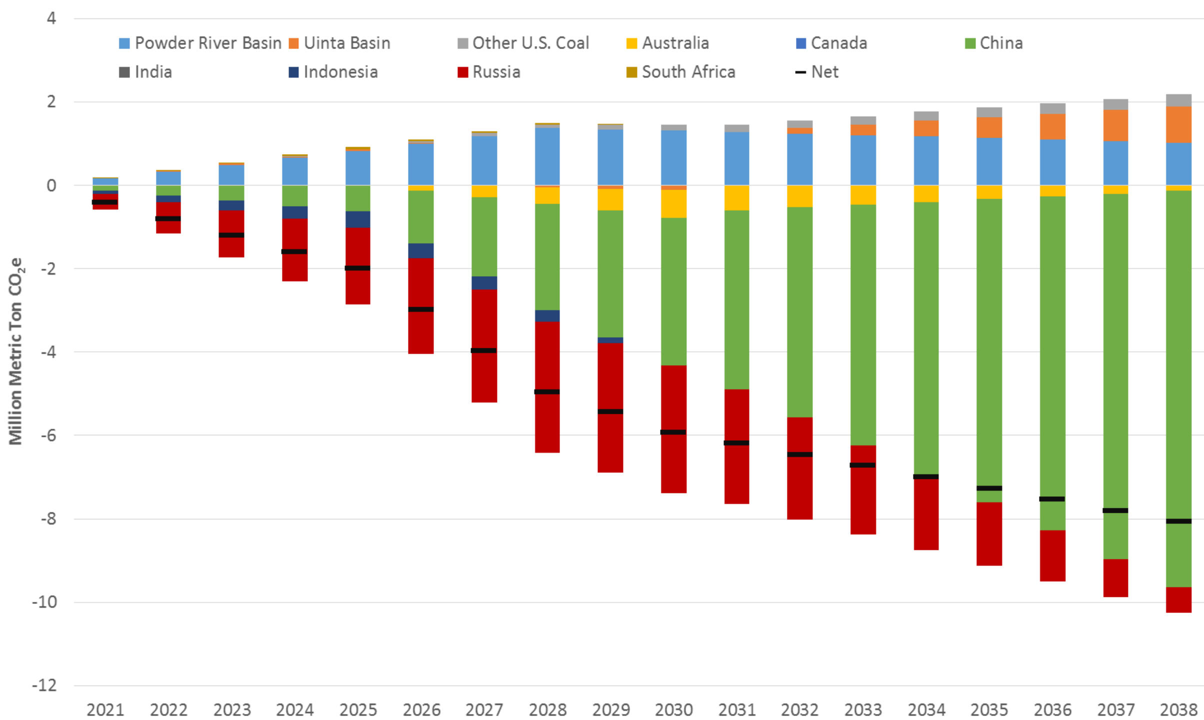
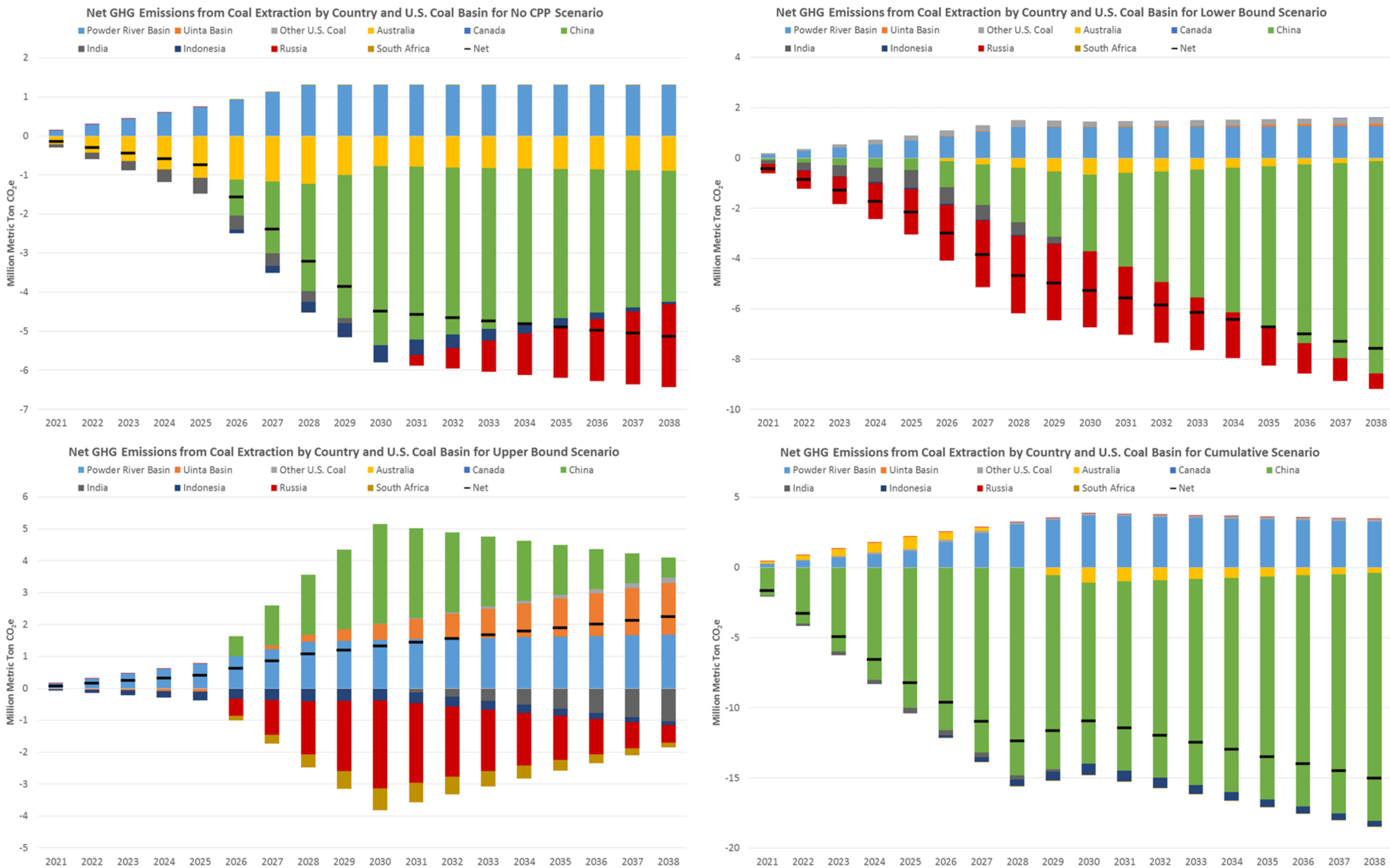


Figure 8. Net GHG Emissions from Coal Extraction by Country and U.S. Coal Basin for No Clean Power Plan, Lower Bound, Upper Bound, and Cumulative Scenarios



As previously mentioned in Section 2.2.2.3, *Method for Impact Analysis,* the uncertainty of the estimates for coal extraction is relatively high. To illustrate this uncertainty, the methane emissions from coal extraction are estimated for a range of emission factors for non-U.S. countries to reflect the -/+ uncertainty of 200% for underground mining and -/+300% for surface mining emission factors. However, use of these uncertainty values resulted in emission factors that are outside the range provided by IPCC for Tier 1 default values, except for in the case of Canadian underground mining. Consequently, the emission factor range for non-U.S. countries is the lower and upper bound as provided by IPCC.[31] The proportion of underground and surface mining relative to total production are from GMI (2015) and were applied to the high and low Tier 1 emission factors following the same method described in Section 2.2.2.3 for countries that did not report to UNFCCC. As part of this uncertainty, a range of emission factors is used for U.S. coal mines based on the uncertainty values provided in the U.S. GHG Inventory (U.S. Environmental Protection Agency 2016b). The uncertainty values for the U.S. estimates are approximately 10% (e.g., an order of magnitude less than the uncertainty estimates used for other countries). Table 45 shows the emission factors used for U.S. basins and non-U.S. countries evaluating the range of net GHG emissions from coal extraction.

Table 45. Range of Coal Mine Methane Emission Factors for Coal Extraction

	Emission Factors (MT CO_2e/MT Coal)		
Coal Basin	**Low**	**Modeled**	**High**
All U.S. Coal - Underground	0.15	0.17	0.20
PRB - Surface	0.02	0.02	0.02
Uinta - Surface	0.01	0.02	0.02
Other U.S. - Surface	0.03	0.03	0.03
Australia	0.04	0.04	0.13
Canada	0.01	0.02	0.04
China	0.16	0.30	0.44
India	0.02	0.05	0.08
Indonesia	0.01	0.02	0.04
Russia	0.05	0.15	0.16
South Africa	0.1	0.19	0.27

Figure 9 and Figure 10 reflect the resulting net GHG emissions for coal extraction. The upper range is based on using the high estimate for the emission factor for countries and basins where coal extraction is increasing, and using the low estimate for the emission factor for countries where coal is being displaced. Alternatively, the lower range is based on using the low estimate for the emission factor for countries and basins where coal extraction is increasing, and using the high estimate for the emission factor for countries where coal is being displaced.

[31] The Canadian upper bound underground emission factor was derived using IPCC's +200% uncertainty value for underground mining.

Figure 9. Range of Net GHG Emissions from Coal Extraction for the 2015 Energy Policy Scenario

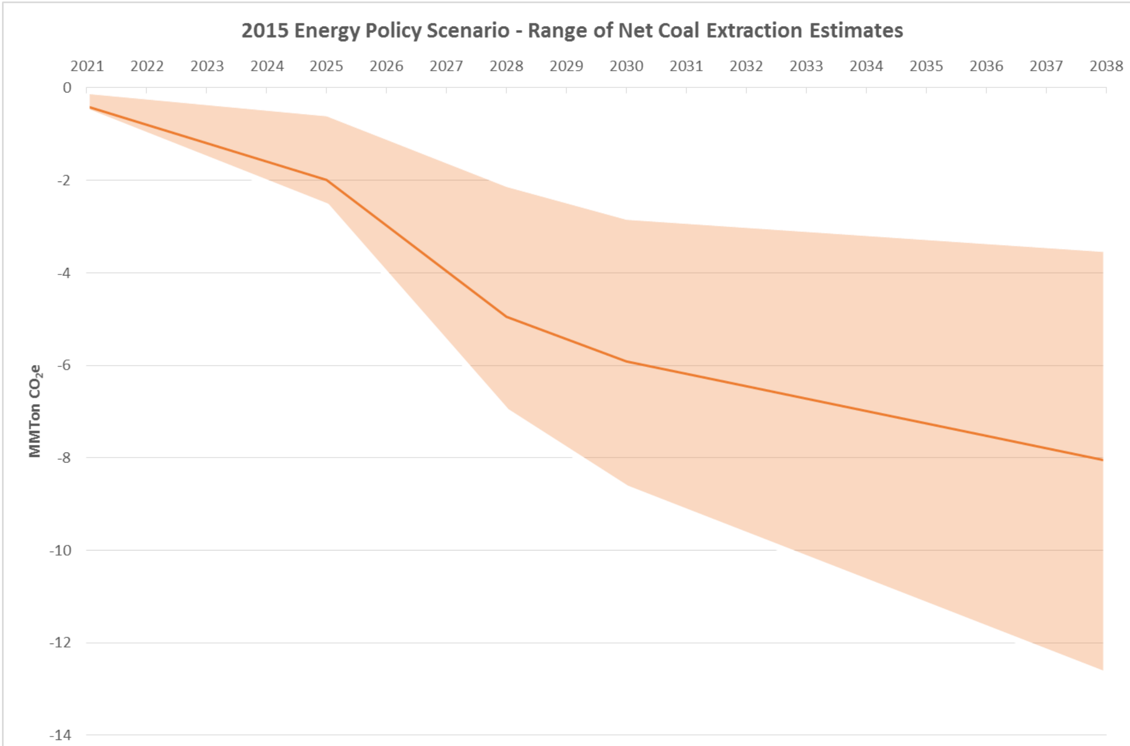


Figure 10. Range of Net GHG Emissions from Coal Extraction for the No CPP, Lower Bound, Upper Bound, and Cumulative Scenarios

3.1.4 Rail Transport

Model results indicate that rail transport across the four scenarios is relatively constant, with slight fluctuations occurring depending on the share of Uinta Basin coal exported via the Proposed Action relative to the Powder River Basin coal. Although the distance from the Uinta Basin to Washington State is shorter than the distance from the Powder River Basin, the majority of the transport emissions occur from the transport of Powder River Basin coal, as its lower price results in higher demand despite the longer distances. The largest source of rail transport emissions is from transport to Washington State. The second largest source of emissions from rail transport is from transport within Washington, which is approximately half the distance as the distance outside Washington State. Once the return trip is taken into account, the difference in emissions between the two routes taken from the different coal basins increases, as empty and loaded Uinta Basin trains return along the same route. Empty Powder River Basin coal trains, however, travel a longer northern route to the Powder River Basin (ICF and Hellerworx 2017).

Emissions from transport of coal within Cowlitz County also vary slightly for Powder River Basin and Uinta Basin coal due to the different directions travelled for empty Powder River Basin and Uinta Basin coal trains. However, due to the small distances involved, this difference does not have a large impact on emissions. The coal market assessment captures changes in the transportation routes from extraction sites to the project area due to shifts in coal demand and prices. Consequently, the emissions change across the scenarios. In Table 47 and Table 48, the Lower Bound scenario has slightly higher total emissions than the No Clean Power Plan and the Upper Bound scenarios because less coal from the Uinta Basin is transported under this scenario. In the Lower Bound scenario, less coal is transported from the Uinta Basin because the higher coal prices assumed under this scenario make the Powder River Basin coal more economical to export than the Uinta Basin coal. Thus, total emissions are higher under the Lower Bound scenario because the total ton-miles of coal transported is greater than in the No Clean Power Plan or Upper Bound scenarios, as the distance from the Powder River Basin is greater than from the Uinta Basin. The on-site emissions are equal across all scenarios, as those emissions are proportional solely to coal throughput for the Proposed Action. Table 46, Table 47, and Table 48 summarize rail emissions for each scenario.

Table 46. Locomotive Emissions from Extraction Sites to Washington State ($MMTCO_2e$)

Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Annual Emissions, 2028 ($MMTCO_2e$)	0.67	0.74	0.63	0.63
Total Emissions, 2018–2038 ($MMTCO_2e$)	9.50	10.63	9.29	8.96

$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

Table 47. Locomotive Emissions within Washington State (Excluding Cowlitz County) ($MMTCO_2e$)[32]

Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Annual Emissions, 2028 ($MMTCO_2e$)	0.32	0.32	0.31	0.32
Total Emissions, 2018–2038 ($MMTCO_2e$)	4.42	4.62	4.12	4.62
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent				

Table 48. Locomotive Operation Emissions within Cowlitz County ($MMTCO_2e$)

Emission Source	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Locomotive Operation, BNSF Main Line & Spur ($MMTCO_2e$)				
Annual Emissions, 2028	0.02	0.02	0.02	0.02
Total Emissions, 2018–2038	0.29	0.29	0.29	0.29
Locomotive Operation, at Terminal Loop ($MMTCO_2e$)				
Annual Emissions, 2028	<0.005	<0.005	<0.005	<0.005
Total Emissions, 2018–2038	0.03	0.03	0.03	0.03
Subtotal ($MMTCO_2e$)				
Annual Emissions, 2028	0.02	0.02	0.02	0.02
Total Emissions, 2018–2038	0.31	0.31	0.31	0.31
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent				

3.1.5 Vehicle-Crossing Delay

The GHG emissions from vehicle-crossing delays are consistent across all four scenarios, as they are directly proportional to the throughput of the Proposed Action. After the start-up period, emissions from this source remain constant throughout the analysis period (Table 49).

[32] Locomotive operation within Cowlitz County is not included in this table, thus results from Table 46, Table 47, and Table 48 are additive.

Table 49. Vehicle-Crossing Delay Emissions from Fossil Fuel Combustion from Vehicles Idling within Cowlitz County ($MtCO_2e$)

Track Section/Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Study Crossings along the Reynolds Lead and BNSF Spur ($MtCO_2e$)				
Annual Emissions, 2028	170	170	170	170
Total Emissions, 2018–2038	2,427	2,427	2,427	2,427
Public At-Grade Crossings along the BNSF Main Line in Cowlitz County ($MtCO_2e$)				
Annual Emissions, 2028	1	1	1	1
Total Emissions, 2018–2038	13	13	13	13
All Vehicle Crossings ($MtCO_2e$)				
Annual Emissions, 2028	171	171	171	171
Total Emissions, 2018–2038	2,439	2,439	2,439	2,439

$MtCO_2e$ = metric tons of carbon dioxide equivalent

3.1.6 Coal Export Terminal Construction

Coal export terminal construction emissions are assumed to occur in an 18-month period prior to the operation of the Proposed Action. Because construction dates are unknown, the GHG analysis assumes that the 18-month construction period would occur at some point between the years 2018 and 2020. For the purposes of estimating emissions associated with coal export terminal operation, the GHG analysis assumes that construction would be completed before the end of 2020. As the construction would be structurally similar across the four scenarios, construction GHG emissions are equal across all four scenarios (Table 50). The emissions from the operation of construction equipment would exceed those of the barges used for bringing construction materials to the project area.

Table 50. Coal Export Terminal Construction Emissions ($MtCO_2e$)

Emission Source	Scenario			
	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Construction Equipment ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	5,349	5,349	5,349	5,349
Total Emissions, 2018–2038[a]	8,024	8,024	8,024	8,024
Employee Commuting ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	465	465	465	465
Total Emissions, 2018–2038[a]	698	698	698	698
Construction Trucks Carrying Materials to Project Area ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	1,081	1,081	1,081	1,081
Total Emissions, 2018–2038[a]	1,621	1,621	1,621	1,621
Construction Barges Carrying Materials to Project Area ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	955	955	955	955
Total Emissions, 2018–2038[a]	1,433	1,433	1,433	1,433
Subtotal ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	7,851	7,851	7,851	7,851
Total Emissions, 2018–2038	11,776	11,776	11,776	11,776

Notes:

[a] Construction emissions occur over an 18-month period prior to the operation of the coal export terminal; therefore, emissions from 2021 through 2038 are zero. Given the 18-month period for construction, total construction emissions are those for the 12-month period multiplied by 1.5.

$MtCO_2e$ = metric tons of carbon dioxide equivalent

The GHG emissions resulting from the production of materials used to construct the coal export terminal occur upstream of the project area. Table 51 summarizes the GHG emissions by general material type. The “Other” category includes plastics and cable wiring, but is mostly composed of the “10% Miscellaneous” materials expected to be used in the construction process. These emissions are assumed to occur once, and have been prorated over the 18-month construction period.

While aggregates compose the majority of total materials mass from berms and roadways (material masses can be found in Table 21, the associated emissions are a minimal portion of the total estimated emissions. In contrast to this distribution of materials, steel materials represent less than 5% of total material mass, but almost 30% of total GHG emissions. This distribution of emission occurs because steel manufacturing emission factors are an order of magnitude higher than any other material due to the energy-intensive nature of the production process.

Table 51. Embedded Emissions in Construction Materials ($MtCO_2e$)

Emission Sources	Scenario: 2015 Energy Policy	Scenario: Lower Bound	Scenario: Upper Bound	Scenario: No Clean Power Plan
Concrete Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	55,818	55,818	55,818	55,818
Total 2018-2038[a]	83,727	83,727	83,727	83,727
Rebar Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	17,489	17,489	17,489	17,489
Total 2018-2038[a]	26,233	26,233	26,233	26,233
Steel Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	33,059	33,059	33,059	33,059
Total 2018-2038[a]	49,588	49,588	49,588	49,588
Aggregates Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	2,225	2,225	2,225	2,225
Total 2018-2038[a]	3,338	3,338	3,338	3,338
Asphalt Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	1,096	1,096	1,096	1,096
Total 2018-2038[a]	1,644	1,644	1,644	1,644
Reinforced Concrete Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	160	160	160	160
Total 2018-2038[a]	239	239	239	239
Other Materials Production and Supply ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	13,781	13,781	13,781	13,781
Total 2018-2038[a]	20,672	20,672	20,672	20,672
Subtotal ($MtCO_2e$)				
Emissions During 12 Months of Construction Period	123,627	123,627	123,627	123,627
Total Emissions, 2018–2038[a]	185,441	185,441	185,441	185,441

Notes:
[a] Construction emissions occur over an 18-month period prior to the operation of the coal export terminal; therefore, embedded emissions in construction materials from 2021 through 2038 are zero. Given the 18-month period for construction, total construction emissions are those for the 12-month period multiplied by 1.5.
$MtCO_2e$ = metric tons of carbon dioxide equivalent

GHG emissions from fuel use occur from initial dock dredging of 500,000 cubic yards of sediment during the construction period. These emissions result from the operation of tugboats and dredging equipment (Table 52).

Table 52. Emissions from Dredging during Construction – Fuel Use ($MtCO_2e$)

	Scenario			
Emission Source	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Emissions from Dredging Operations ($MtCO_2e$)				
Emissions During 12 Months of Construction Period[a]	188	188	188	188
Total Emissions, 2018–2038[a]	377	377	377	377

Notes:

[a] Construction emissions occur over an 18-month period prior to the operation of the coal export terminal; therefore, emissions from 2021 through 2038 are zero. Emissions from maintenance dredging occur during the operational phase; however, these are presented in Section 3.1.7, *Coal Export Terminal Operation—Equipment Operation*. Dredging is expected to occur over two annual approved work periods to coincide with fish protection during the construction phase (Millennium Bulk Terminal—Longview 2014). One of the approved work periods is assumed to coincide with the 12 months of construction period, while the second dredging event is assumed to occur within the following year. Therefore, emissions during the 12 months of construction period shown above are assumed to be half of the total emissions during the entire construction period from 2018-2020.

$MtCO_2e$ = metric tons of carbon dioxide equivalent

3.1.7 Coal Export Terminal Operation—Equipment Operation

GHG emissions from mobile equipment used for routine operation of the coal export terminal are consistent across all four scenarios, as they are directly proportional to the throughput of the Proposed Action (Table 53). After the start-up period, emissions from this source would remain constant throughout the analysis period.

Table 53. Coal Export Terminal Operation Emissions from Mobile Combustion ($MtCO_2e$)

	Scenario			
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Annual Emissions, 2028 ($MtCO_2e$)	908	908	908	908
Total Emissions, 2018–2038 ($MtCO_2e$)	12,977	12,977	12,977	12,977

$MtCO_2e$ = metric tons of carbon dioxide equivalent

GHG emissions from fuel use occur from maintenance dock dredging of an estimated 100,000 cubic yards per year of sediment during the operations period. These emissions result from the operation of tugboats and dredging equipment (Table 54).

Table 54. Dredging Emissions during Operations – Fuel Use ($MtCO_2e$)

	Scenario			
Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Annual Emissions, 2028 ($MtCO_2e$)	75	75	75	75
Total Emissions, 2018–2038 ($MtCO_2e$)	1,355	1,355	1,355	1,355

$MtCO_2e$ = metric tons of carbon dioxide equivalent

3.1.8 Coal Export Terminal Operation—Electricity Consumption

Electricity consumption emissions for operation of the new coal export terminal are assumed constant across all years of the analysis period and for all scenarios (Table 55).

Table 55. Coal Export Terminal Operation—Indirect Emissions from Electricity Consumption ($MtCO_2e$)

	Scenario			
Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Annual Emissions, 2028 ($MtCO_2e$)	177	177	177	177
Total Emissions, 2018–2038 ($MtCO_2e$)	3,191	3,191	3,191	3,191

$MtCO_2e$ = metric tons of carbon dioxide equivalent

3.1.9 Employee Commuting

GHG emissions from employee commuting are consistent across all four scenarios, as they are directly proportional to the throughput of the Proposed Action (Table 56). After the start-up period, emissions from this source would remain constant throughout the analysis period.

Table 56. Employee Commuting ($MtCO_2e$)

	Scenario			
Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Annual Emissions, 2028 ($MtCO_2e$)	275	275	275	275
Total Emissions, 2018–2038 ($MtCO_2e$)	3,922	3,922	3,922	3,922

$MtCO_2e$ = metric tons of carbon dioxide equivalent

3.1.10 Vessel Idling and Tugboat Use at Coal Export Terminal

GHG emissions from idling vessels and tugboats are consistent across all four scenarios, as they are directly proportional to the throughput of the Proposed Action (Table 57). Tugboats emit approximately twice as many emissions as idling vessels. After the start-up period, emissions from this source remain constant throughout the analysis period.

Table 57. Emissions from Vessel Idling and Tugboat Use at Coal Export Terminal ($MtCO_2e$)

	Scenario			
Emission Source	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Vessel Idling at Terminal ($MtCO_2e$)				
Annual Emissions, 2028	2,498	2,498	2,498	2,498
Total Emissions, 2018–2038	35,660	35,660	35,660	35,660
Tugboat Operation ($MtCO_2e$)				
Annual Emissions, 2028	4,840	4,840	4,840	4,840
Total Emissions, 2018–2038	69,081	69,081	69,081	69,081
Subtotal ($MtCO_2e$)				
Annual Emissions, 2028	7,338	7,338	7,338	7,338
Total Emissions, 2018–2038	104,740	104,740	104,740	104,740
$MtCO_2e$ = metric tons of carbon dioxide equivalent				

3.1.11 Helicopter and Pilot Boat Trips

GHG emissions from pilot transfers are consistent across all four scenarios, as they are directly proportional to the throughput of the Proposed Action (Table 58). Helicopters emit about the same GHGs as pilot boats and are assumed responsible for 70% of the pilot transfers. After the start-up period, emissions from this source would remain constant throughout the analysis period.

Table 58. Emissions from Helicopter and Pilot Boat Trips for Pilot Transfers to Vessels ($MtCO_2e$)

	Scenario			
Emission Source	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Helicopter Operation ($MtCO_2e$)				
Annual Emissions, 2028	180	180	180	180
Total Emissions, 2018–2038	2,575	2,575	2,575	2,575
Pilot Boat Operation ($MtCO_2e$)				
Annual Emissions, 2028	198	198	198	198
Total Emissions, 2018–2038	2,827	2,827	2,827	2,827
Subtotal ($MtCO_2e$)				
Annual Emissions, 2028	378	378	378	378
Total Emissions, 2018–2038	5,402	5,402	5,402	5,402
$MtCO_2e$ = metric tons of carbon dioxide equivalent				

3.1.12 Vessel Transport

Vessel transport GHG emissions are equivalent across all scenarios within Cowlitz County and Washington State but diverge for international transport (Table 59 and Table 60). The differences in international transport emissions result from different destinations for the exported coal and the extent to which demand for existing sources of Asian coal is substituted, primarily by coal from Indonesia, China, Russia, Australia, and India Consequently, the net emissions from international transport of coal include both transport to the Asian market and the adjustment for the substituted vessel transport from other international coal production sources to the Asian market (Table 61). In all of the scenarios, the addition of 44 million metric tons of coal would displace less than 44 million metric tons of coal traffic within the Pacific Basin because of differences in the heat content of the coals. In the Upper Bound scenario, displacement of international coal is less than in other scenarios because coal demand increases due to induced demand, and thus the amount of coal displaced by the proposed coal export terminal is even less than in other scenarios.

Table 59. Emissions from Vessel Transport within Cowlitz County ($MMTCO_2e$)

	Scenario			
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Annual Emissions, 2028 ($MMTCO_2e$)	0.01	0.01	0.01	0.01
Total Emissions, 2018–2038 ($MMTCO_2e$)	0.12	0.12	0.12	0.12

$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

Table 60. Emissions from Vessel Transport within Washington State (Excluding Transport within Cowlitz County) ($MMTCO_2e$)[33]

	Scenario			
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Annual Emissions, 2028 ($MMTCO_2e$)	0.01	0.01	0.01	0.01
Total Emissions, 2018-2038 ($MMTCO_2e$)	0.15	0.15	0.15	0.15

$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

[33] This table does not include emissions generated from vessel transport within Cowlitz County so that the results in Table 59, Table 60, and Table 61 are additive.

Table 61. Net Emissions from Changes in International Vessel Transport to Asian Markets ($MMTCO_2e$)[a]

	Scenario			
Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan
Net Annual Emissions, 2028 ($MMTCO_2e$)	1.01	1.13	1.12	0.93
Net Total Emissions, 2018–2038 ($MMTCO_2e$)	15.16	16.17	16.87	13.32

[a] Net GHG emissions represent the difference between the Proposed Action and the no-action.
$MMTCO_2e$ = metric tons of carbon dioxide equivalent

3.1.13 Coal Combustion

Coal combustion in the United States and Asia is one of the largest and most variable sources of GHG emissions associated with the Proposed Action. Model results indicate that this source of emissions varies significantly throughout the analysis period and between scenarios, indicating that it is sensitive to policy and market factors. For most scenarios, the coal combustion emissions in the United States decrease while coal combustion emissions in Asia increase, to varying degrees. The key factor behind this shift is U.S. and Asian markets' reactions to price and supply shifts for coal. As the Proposed Action exports U.S. coal, prices in the United States go up in response to supply decreasing, thus reducing coal combustion. Likewise, the increased supply of coal in Asia decreases prices and facilitates additional coal combustion.

Coal combustion emissions in Asia are separated in Table 62 into two subcategories: emissions from induced coal demand and emissions from coal substitution. Induced demand emissions would occur because of lowered coal prices in response to an increase in coal supply caused by the Proposed Action. Coal substitution emissions are a result of one of two processes. In the first process, lower-heat-content coal displaces higher-heat-content coal, which results in a net increase in emissions to generate the same amount of energy. In the second process, coal with a higher CO_2 emissions rate displaces coal with a lower CO_2 emissions rate, which also results in a net increase in emissions. Both of these processes may occur in reverse as well, which would result in lower net emissions.

The differences between scenarios are driven by the following factors.

- Coal combustion emissions in the United States are less than the no-action for all scenarios, except for the Upper Bound scenario. Thus the net emissions from coal combustion are negative in the United States except for the Upper Bound scenario. Domestic coal prices increase in every scenario in response to the export of Powder River Basin and Uinta Basin coal. The higher prices then reduce the U.S. demand for coal, except in the Upper Bound scenario. In the Upper Bound scenario, changes in solar and combined cycle builds in the North and South Carolina electric demand region result in increases in coal consumption by an average of 0.40 million metric tons per year over the 2025 through 2040 period.[34]
- In the Upper Bound scenario, the additional coal exported to Asia from the Proposed Action reduces the delivered Asia coal prices, inducing demand. This increases overall coal

[34] A solar build of 29 megawatts is delayed in the Proposed Action from coming online in 2020 to coming online in 2030. Also, there is 4 megawatts less combined cycle builds. Both actions result in greater coal consumption.

consumption even as some Asian coals from Indonesia and Australia are substituted by Powder River Basin and Uinta Basin coals.

- There is a secondary driver of emissions in Asia, as lower-heat-content coal from the United States is a substitute for higher-heat-content coal, or higher-CO_2-content coal is a substitute for lower-CO_2-content coal. This substitution of higher-heat-content coal results in additional low-heat-content coal being combusted in order to meet electricity demands (i.e., Btu demands), therefore raising emissions in Asia.[35] There is an increase in CO_2 combustion emissions due to this driver in all but the Lower Bound scenario.
- In the 2015, U.S. and International Energy Policy scenario, the increase in Asian CO_2 emission is driven by the mix of coal consumed. U.S. coal consumption decreases slightly relative to the no-action because U.S. coal prices are already low due to a decrease in consumption from the enactment of EPA's Clean Power Plan in 2022, as modeled.

The coal market assessment provides a thorough discussion of the market.

Table 62. Net Emissions from Coal Combustion ($MMTCO_2e$)[a]

	Scenario			
Emission Source	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Coal Combustion, United States ($MMTCO_2e$)				
Net Annual Emissions, 2028	-1.25	-7.94	0.03	<0.005
Net Total Emissions, 2018–2038	-14.02	-93.59	0.77	-0.04
Coal Combustion from Induced Demand, Asia ($MMTCO_2e$)				
Net Annual Emissions, 2028	0	<0.005	52.48	0
Net Total Emissions, 2018–2038	0	<0.005	747.07	0
Coal Combustion from Coal Substitution, Asia ($MMTCO_2e$)				
Net Annual Emissions, 2028	0.32	-0.54	0.41	1.84
Net Total Emissions, 2018–2038	5.47	-7.86	1.62	23.95
Subtotal ($MMTCO_2e$)				
Net Annual Emissions, 2028	-0.93	-8.48	52.92	1.83
Net Total Emissions, 2018–2038	-8.55	-101.44	749.46	23.91

Notes:
[a] Net GHG emissions represent the difference between the Proposed Action and the no-action.
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

3.1.14 Induced Natural Gas Consumption

Natural gas consumption in the United States is a large and highly variable source of emissions. Higher coal prices or lower natural gas prices in the United States induce electricity generators to switch to natural gas. Relative to the no-action, natural gas emissions increase for all scenarios except for the Upper Bound scenario, although the results display significant variation depending on

[35] For example, for the No Clean Power Plan scenario, coal consumption in Taiwan increases by 1.7 million metric tons in 2025 over the no-action; however, there is no induced demand in this scenario. Thus the full 1.7 million metric tons of the increase in coal consumption in Taiwan in 2025 is due to changes in the mix of coal consumed.

the extent to which coal is displaced (Table 63). The differences among scenarios are driven by the following two factors.

- The inclusion of the Clean Power Plan, which generally reduces coal consumption and prices and increases natural gas consumption and prices. One of the components of compliance with the Clean Power Plan is increased energy efficiency. Thus in the scenarios without the Clean Power Plan the increased energy efficiency is removed, which results in overall electric demand being higher. This results in higher coal and natural gas consumption in the scenarios without the Clean Power Plan in 2025 and later when the Clean Power Plan implementation is ramped up.
- The assumed Powder River Basin coal production costs. Higher Powder River Basin coal production costs, as in the Lower Bound scenario, result in a greater increase in natural gas consumption under the Proposed Action, because there is a greater increase in coal prices. The greater increase in coal prices results in a larger decrease in coal consumption and a subsequent larger increase in natural gas consumption.

Table 63. Net Emissions from Natural Gas Substitution in the United States ($MMTCO_2e$)[a]

	Scenario			
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Net Annual Emissions, 2028 ($MMTCO_2e$)	0.07	2.42	-0.02	<0.005
Net Total Emissions, 2018–2038 ($MMTCO_2e$)	0.89	27.78	-0.24	<0.005

Notes:
[a] Net GHG emissions represent the difference between the Proposed Action and the no-action.
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

3.1.15 Net Greenhouse Gas Emissions

This section presents the aggregated results of each of the emission sources described previously.

Model results indicate that the direct GHG emissions from the Proposed Action (Table 64) are the same for each of the four scenarios, as they are emitted in proportion to the throughput of the Proposed Action and are not influenced by outside economic factors. The largest contributors to the direct emissions are transportation-related emissions, including locomotive operation and vessel transport within Cowlitz County. Together, these two sources contribute about 72% of direct emissions. For the 2015 U.S. and International Energy Policy scenario, the total direct emissions contributed an increase of approximately 0.60 $MMTCO_2e$ (0.9%) (Table 64). This value is compared to a total net increase in emissions of 22.36 $MMTCO_2e$ excluding coal extraction (Table 66) and a net decrease in emissions of 63.54 $MMTCO_2e$ including coal extraction (Table 67) throughout the 2018 through 2038 analysis period once market-influenced and indirect sources of emissions are considered.

Table 64. Direct Emissions (Generated in Cowlitz County) for the Proposed Action ($MMTCO_2e$)[36]

	Scenario			
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**
Annual Emissions, 2028 ($MMTCO_2e$)	0.04	0.04	0.04	0.04
Total Emissions, 2018–2038 ($MMTCO_2e$)	0.60	0.60	0.60	0.60

$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

Statewide, emissions are about 9 times as high as the county emissions, largely driven by the greater distances traveled by locomotives and vessels outside of Cowlitz County. Locomotive transport constitutes about 97% of emissions generated within Washington State and outside of Cowlitz County (Table 65).

Table 65. Emissions Generated within Washington State, Excluding Cowlitz County ($MMTCO_2e$)

	Scenario				
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**	**Cumulative**
Annual Emissions, 2028 ($MMTCO_2e$)	0.33	0.33	0.32	0.33	0.33
Total Emissions, 2018–2038 ($MMTCO_2e$)	4.57	4.77	4.27	4.77	4.77

Notes:
The Cumulative scenario is provided here for comparison and is addressed in Section 3.1.15, *Net Greenhouse Gas Emissions*, under *Cumulative Scenario*.
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

The total net indirect emissions from activities outside the project area and Cowlitz County attributed to the operation of the Proposed Action come from a variety of sources, including:

- Extraction of coal at the mining sites
- Rail Transport
- Coal export terminal construction—embedded GHG emissions in materials for coal export terminal construction
- Coal Export Terminal Operation—Electricity Consumption
- Helicopter and Pilot Boat Trips
- Vessel Transport
- Coal Combustion in Asia and the United States
- Induced Natural Gas Consumption in the United States

Net indirect emissions over the 2018 through 2038 analysis period excluding coal extraction vary depending on the scenario, from a decrease of 41.904 $MMTCO_2e$ in the Lower Bound scenario to an increase of 779.83 $MMTCO_2e$ in the Upper Bound scenario (Table 66). The total net impacts (i.e., direct and indirect emissions) excluding coal extraction range from a decrease in emissions of 41.31 $MMTCO_2e$ in the Lower Bound scenario relative to the no-action to an increase in emissions of 780.42 $MMTCO_2e$ in the Upper Bound scenario relative to the no-action. The No Clean Power Plan

[36] By definition, direct emissions are equivalent to emissions generated in Cowlitz County.

scenario, which depicts a "business as usual" projection of market conditions in the absence of climate policy, indicates a net increase of 51.75 $MMTCO_2e$ across the entire analysis period studied. Table 66 summarizes direct emissions, indirect emissions, and total net emissions excluding coal extraction.

Table 66. Net (Direct and Indirect) Emissions for the Proposed Action Excluding Coal Extraction ($MMTCO_2e$)

	Scenario				
Period	**2015 Energy Policy**	**Lower Bound**	**Upper Bound**	**No Clean Power Plan**	**Cumulative**
Direct emissions (generated in Cowlitz County) excluding coal extraction ($MMTCO_2e$)					
Annual Emissions, 2028	0.04	0.04	0.04	0.04	0.04
Total Emissions, 2018–2038	0.60	0.60	0.60	0.60	0.60
Net indirect emissions excluding coal extraction ($MMTCO_2e$)					
Annual Emissions, 2028	1.15	-3.84	54.97	3.72	19.45
Total Emissions, 2018–2038	21.76	-41.90	779.83	51.16	350.64
Net emissions (direct + indirect) excluding coal extraction ($MMTCO_2e$)					
Annual Emissions, 2028	1.19	-3.80	55.01	3.76	19.49
Total Emissions, 2018–2038	22.36	-41.31	780.42	51.75	351.24

Notes:
The Cumulative scenario is provided here for comparison and is addressed in Section 3.1.15, *Net Greenhouse Gas Emissions*, under *Cumulative Scenario*
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

Net indirect emissions over the 2018 through 2038 analysis period including coal extraction vary depending on the scenario, from a decrease of 122.64 $MMTCO_2e$ in the Lower Bound scenario to an increase of 800.90 $MMTCO_2e$ in the Upper Bound scenario (Table 67). The total net impacts (i.e., direct and indirect emissions) including coal extraction range from a decrease in emissions of 122.04 $MMTCO_2e$ in the Lower Bound scenario relative to the no-action to an increase in emissions of 801.49 $MMTCO_2e$ in the Upper Bound scenario relative to the no-action. The No Clean Power Plan scenario, which depicts a "business as usual" projection of market conditions in the absence of climate policy, indicates a net decrease of 4.75 $MMTCO_2e$ across the entire analysis period studied. Table 67 summarizes direct emissions, indirect emissions, and total net emissions including coal extraction.

Table 67. Net Emissions (Direct + Indirect) for the Proposed Action Including Coal Extraction ($MMTCO_2e$)[a]

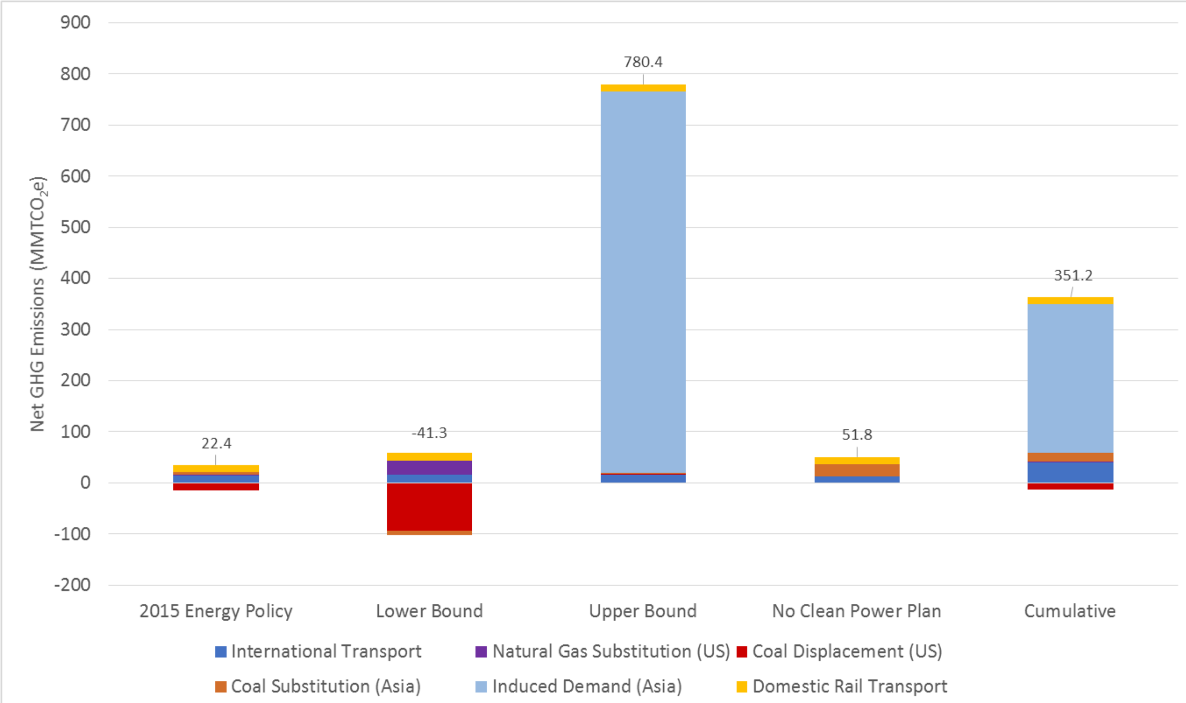
	Scenario				
Period	2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan	Cumulative
Direct emissions (generated in Cowlitz County) including coal extraction ($MMTCO_2e$)					
Annual Emissions, 2028	0.04	0.04	0.04	0.04	0.04
Total Emissions, 2018–2038	0.60	0.60	0.60	0.60	0.60
Net indirect emissions including coal extraction ($MMTCO_2e$)					
Annual Emissions, 2028	-3.77	-8.52	56.05	0.51	7.11
Total Emissions, 2018–2038	-64.14	-122.64	800.90	-5.34	164.83
Net emissions (direct + indirect) including coal extraction ($MMTCO_2e$)					
Annual Emissions, 2028	-3.73	-8.48	56.09	0.55	7.15
Total Emissions, 2018–2038	-63.54	-122.04	801.49	-4.75	165.43

Notes:
[a] Net GHG emissions represent the difference between the Proposed Action and the no-action.
$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

Figure 11 depicts the range of net total emissions from the operation of the Proposed Action excluding coal extraction across the different scenarios studied.[37] This figure, which identifies the major sources of emissions, shows that the largest contributors to net emissions vary across scenarios. In the 2015 U.S. and International Energy Policy scenario, international vessel transportation is the largest contributor to net emissions. In the Lower Bound scenario, coal displacement in the United States is the largest contributor to net emissions. In the No Clean Power Plan scenario, coal substitution in Asia is the largest contributor to net emissions, while in the Upper Bound and Cumulative scenarios, induced demand in Asia is the largest contributor to net emissions.

[37] The bars in this figure do not include some of the smaller sources of emissions (for instance on-site emissions are not included). However, the number for each bar denotes the total net emissions for each scenario modeled and includes all emission sources.

Figure 11. Total Net Emissions for Each Scenario, Excluding Coal Extraction 2018-2038 ($MMTCO_2e$)[a]

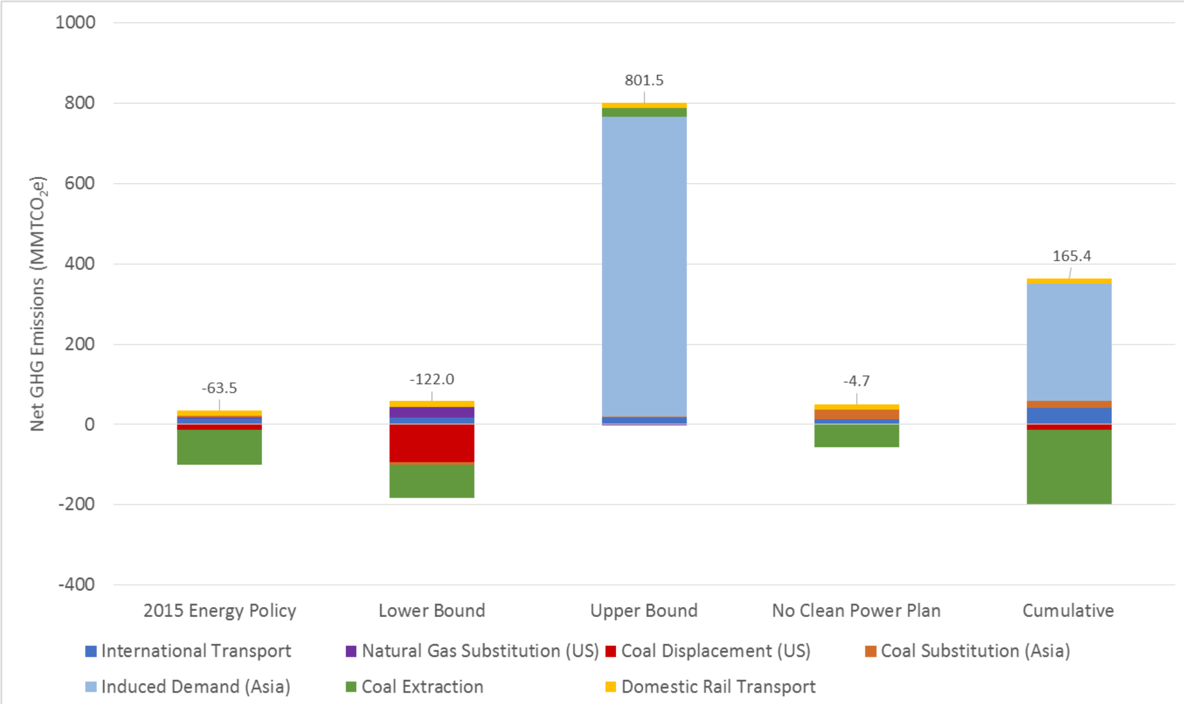


Notes: [a] Net GHG emissions represent the difference between the proposed action and the no-action. The bars in this figure do not include some of the smaller sources of emissions (for instance on-site emissions are not included). However, the number for each bar denotes the total net emissions for each scenario modeled and includes all emission sources apart from coal extraction. The Cumulative scenario is provided here for comparison and is addressed in Section 3.1.15, *Net Greenhouse Gas Emissions*, under *Cumulative Scenario*

Figure 12 depicts the range of net total emissions from the operation of the Proposed Action, including coal extraction across the different scenarios studied.[38] Similar to Figure 11, this figure also shows that the largest contributors to net emissions vary across scenarios. In the 2015 U.S. and International Energy Policy and No Clean Power Plan scenarios, coal extraction is the largest contributor to net emissions, In the Lower Bound scenario, coal displacement in the United States is the largest contributor to net emissions, while in the Upper Bound and Cumulative scenario, induced demand in Asia is the largest contributor to net emissions.

[38] The bars in this figure do not include some of the smaller sources of emissions (for instance on-site emissions are not included). However, the number for each bar denotes the total net emissions for each scenario modeled and includes all emission sources.

Figure 12. Total Net Emissions for Each Scenario, Including Coal Extraction 2018-2038 ($MMTCO_2e$)[a]

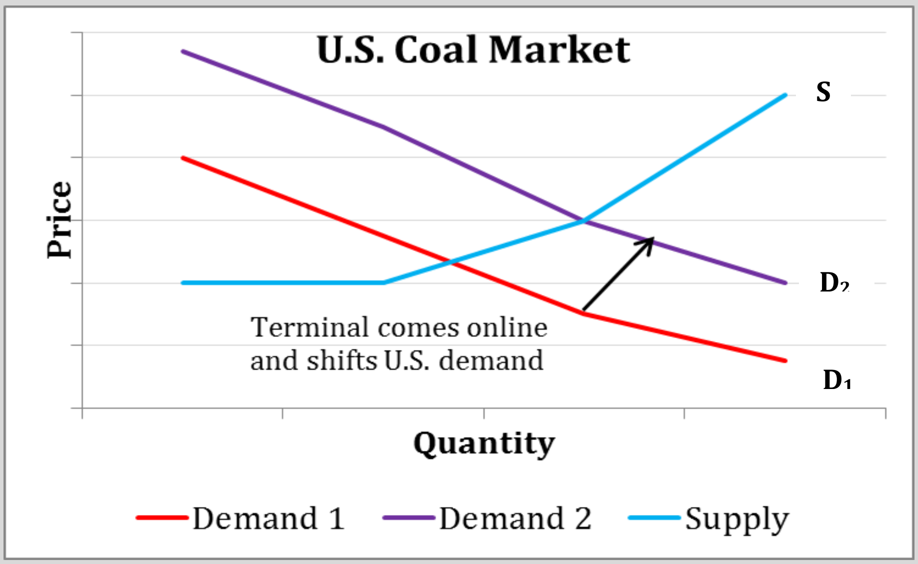


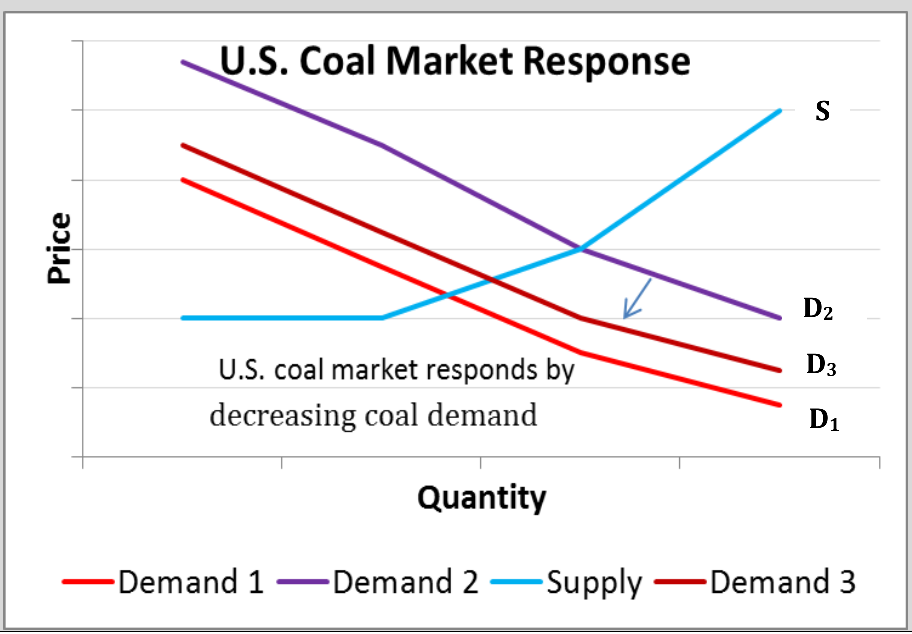
Notes: [a] Net GHG emissions represent the difference between the Proposed Action and the no-action. The bars in this figure do not include some of the smaller sources of emissions (for instance on-site emissions are not included). However, the number for each bar denotes the total net emissions for each scenario modeled and includes all emission sources. The Cumulative scenario is provided here for comparison and is addressed in Section 3.1.15, *Net Greenhouse Gas Emissions*, under *Cumulative Scenario*

The shift in coal prices both domestically and internationally have a major impact on the resulting net GHG emissions for each scenario compared to the no-action. The textboxes that follow illustrate key concepts on the shift in coal prices. These shifts are mentioned as they influence the net change in GHG emissions as described below. For additional details, see the SEPA Coal Market Assessment Technical Report (ICF 2017c).

Impact of the Proposed Action on Domestic Coal Supply and Demand, Assuming Coal Export Terminal Operates at Full Capacity

The operation of the Proposed Action would have the effect of improving integration of the U.S. and Asian coal markets. However, to the extent that Asian coal prices are higher than U.S. coal prices, operation of the Proposed Action would cause Asian coal prices to decline, while U.S. coal prices would increase. These changes in price would cause Asian coal demand to increase and U.S. coal demand to decrease. Increase in demand for U.S. coal as coal is exported from the Proposed Action (D_1 shifts to D_2) would result in higher U.S. coal prices and a subsequent decrease in domestic coal demand compared to the no-action. The international "demand" from the coal export terminal is inelastic (i.e., for a 1% change in coal price, there is no change in demand for coal from the export terminal) while the domestic demand from coal plants is elastic and decreases with an increase in coal prices (e.g., for a 1% increase in coal price, the demand for coal will decrease 0.3%).





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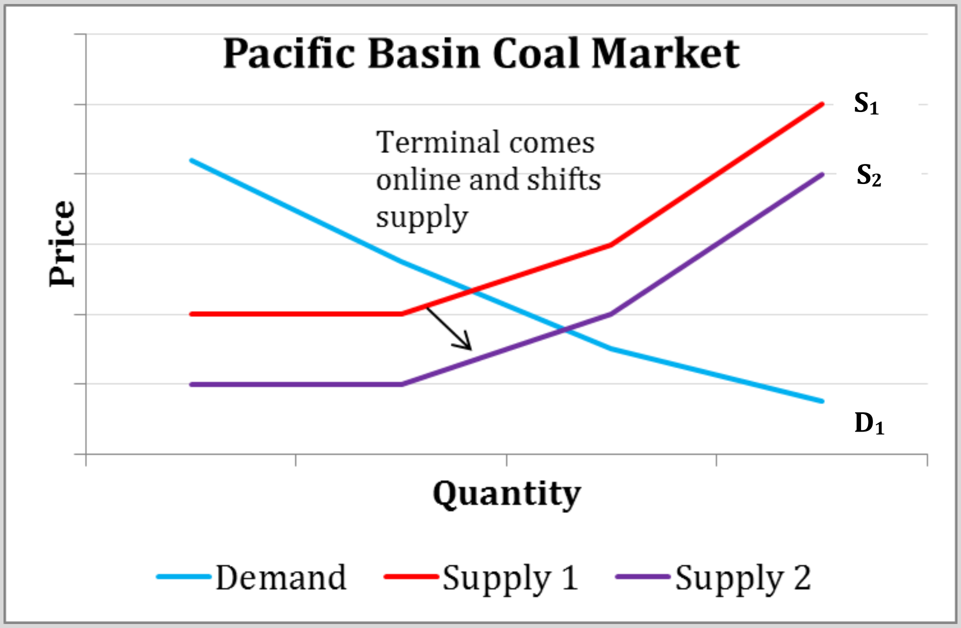
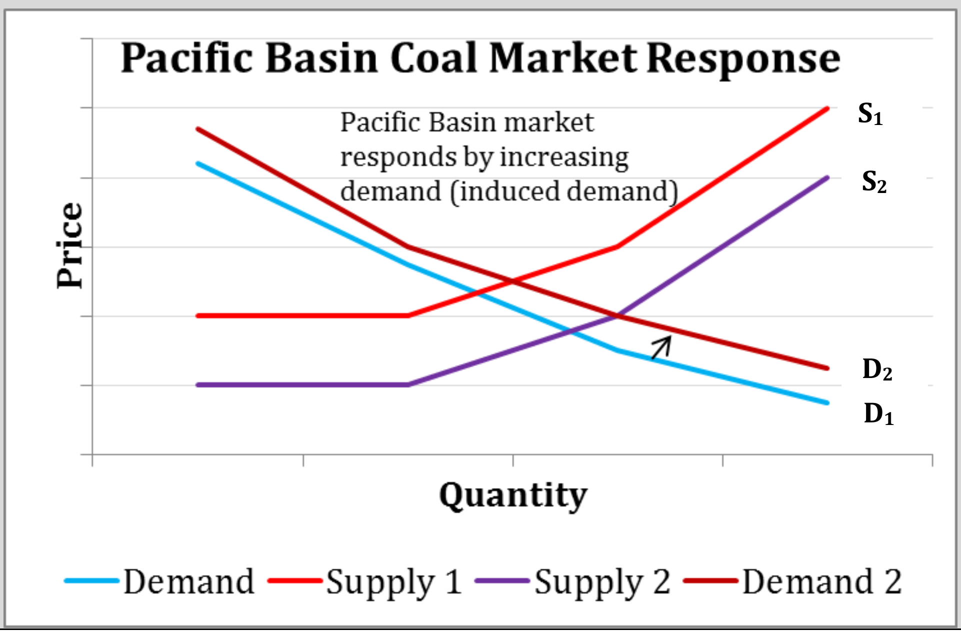
Impact of the Proposed Action on International Coal Supply and Demand, Assuming Coal Export Terminal Operates at Full Capacity

1. Increase in coal supplied to international market from the Proposed Action.
2. This increase in the coal supply in Asia would result in lower international coal prices and a subsequent increase in international coal demand compared to the no-action.





The diagrams above explain the general impact of the Proposed Action on coal markets regardless of the scenario. What makes each scenario different, however, is that the supply and demand curves for coal each have different slopes. The slopes of the supply and demand curves vary based on economic and policy conditions dictated by each scenario. For example, the Lower Bound scenario has a lower slope for coal demand than the No Clean Power Plan scenario, indicating a lower elasticity of demand in response to supply changes. Likewise, the slope of the demand curves in the Upper Bound Scenario is higher than the No Clean Power Plan Scenario, which results in greater elasticity of demand and thus greater induced demand. In effect, the differences in supply and demand curves differentiate the emissions between each scenario.

3.1.15.1 No Clean Power Plan Scenario

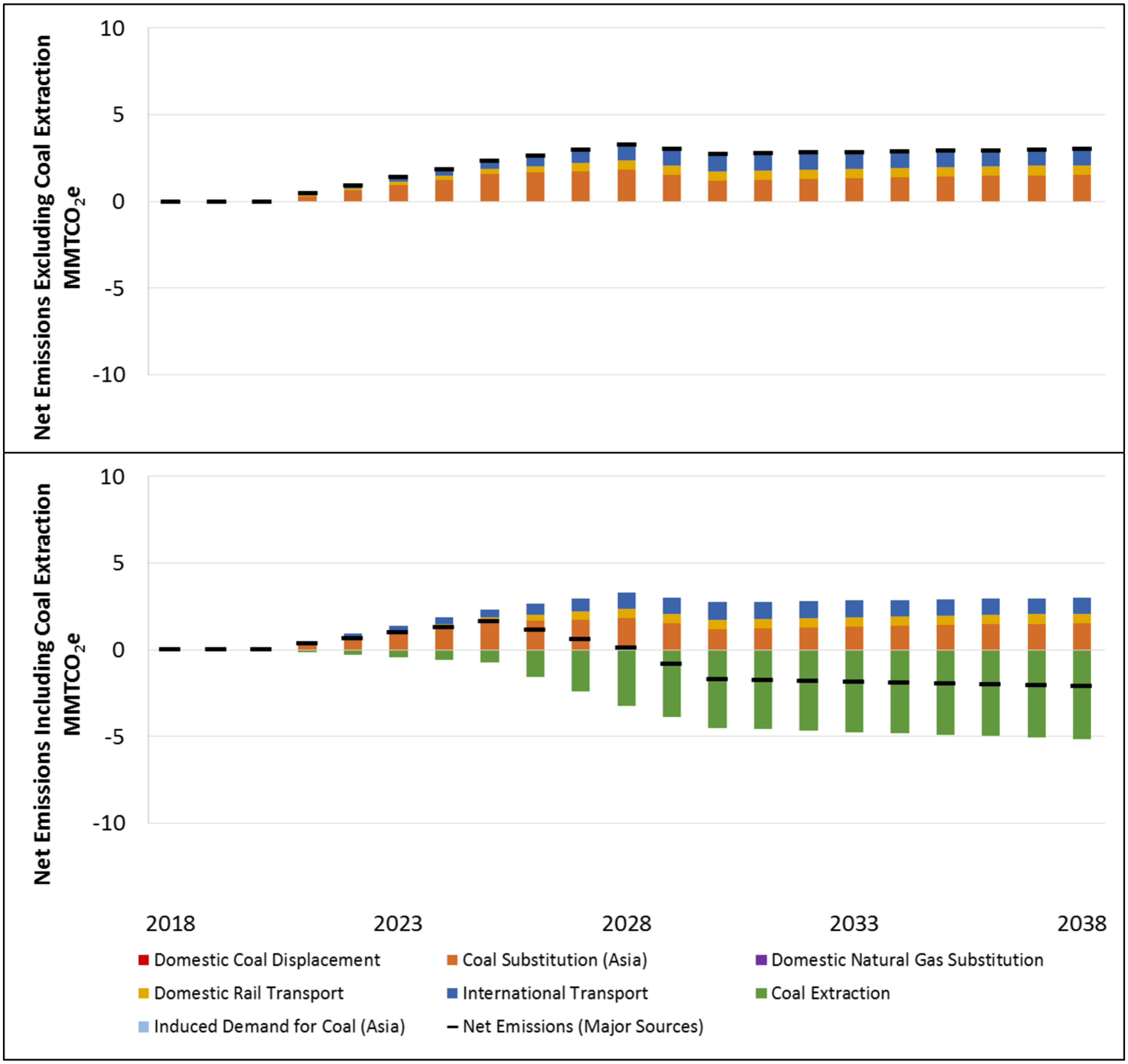
Emissions estimated in the coal market assessment are assumed zero from 2018 through 2020 because the proposed terminal is not operating yet. Emissions start to ramp up when the coal export terminal would begin operating in 2021 and continue through 2038. As shown in Figure 13, there is significant variation from year to year, as well as a ramp-up period where the coal export terminal would increase exports from zero to 44 million metric tons of coal per year. In the No Clean Power Plan Scenario, U.S. coal consumption and thus emissions do not change under the Proposed Action because domestic coal prices do not increase enough to cause a change in demand. The coal exported through the proposed terminal replaces coal produced primarily from Indonesia, China, Russia, Australia, and India, resulting in a net decrease in annual GHG emissions of 3.21 million metric tons from coal extraction when the terminal reaches full capacity in 2028 (Table 44).

Impacts on Coal and Natural Gas Combustion Relative to the No Clean Power Plan Scenario

The table below compares how coal and natural gas combustion change in response to market and policy conditions. The No Clean Power Plan scenario row compares the emissions relative to the no-action, whereas the other rows indicate whether emissions have increased or decreased relative to the no-action and then indicate whether the magnitude of this increase or decrease is greater than or less than the increase or decrease from the No Clean Power Plan scenario.

Scenario	U.S. Coal Combustion	Asian Coal Combustion	U.S. Natural Gas Combustion
No Clean Power Plan	Decrease in domestic coal emissions compared to the no-action due to slight decrease in coal consumption.	Increase in Asian coal emissions compared to the no-action due to the change in the mix of coal consumed.	Increase in domestic natural gas emissions compared to the no-action due to the slight decrease in coal consumption.
2015 U.S. and International Energy Policy	Decrease in domestic coal emissions compared to the no-action.	Increase in Asian coal emissions compared to the no-action.	Increase in domestic natural gas emissions compared to the no-action.
	Magnitude of decrease is greater than of the No Clean Power Plan due to greater sensitivity to coal price changes due to overall lower electric demand.	Magnitude of increase is less than that of the No Clean Power Plan due to a different mix of coals consumed.	Magnitude of increase is greater than that of the No Clean Power Plan due to the greater decrease in coal consumption.
Lower Bound	Decrease in domestic coal emissions compared to the no-action.	Decrease in Asian coal emissions compared to the no-action.	Increase in domestic natural gas emissions compared to the no-action.
	Magnitude of the decrease is greater than that of the No Clean Power Plan due to the higher assumed production costs in the Powder River Basin that result in higher coal prices in the Proposed Action that results in greater reduction of domestic coal consumption.	Magnitude of the decrease is less than in the No Clean Power Plan. In both scenarios the changes in Asian coal combustion emissions are due only to changes in the mix of coal consumed.	Magnitude of the increase in natural gas emissions is greater than in the No Clean Power Plan due to the greater reduction in coal consumption.
Upper Bound	Increase in domestic coal emissions compared to the no-action.	Increase in Asian coal emissions compared to the no-action.	Decrease in domestic natural gas emissions compared to the no-action.
	Magnitude of the decrease is greater than in the No Clean Power Plan scenario due to the higher overall demand for coal	Magnitude of the increase is greater than in the No Clean Power Plan scenario because the higher assumed production costs of international coal producers results in greater induced demand.	Magnitude of decrease is greater than in the No Clean Power Plan scenario because of the greater change in domestic coal consumption.

Figure 13. No Clean Power Plan—Net Annual Emissions Excluding and Including Coal Extraction, 2018–2038



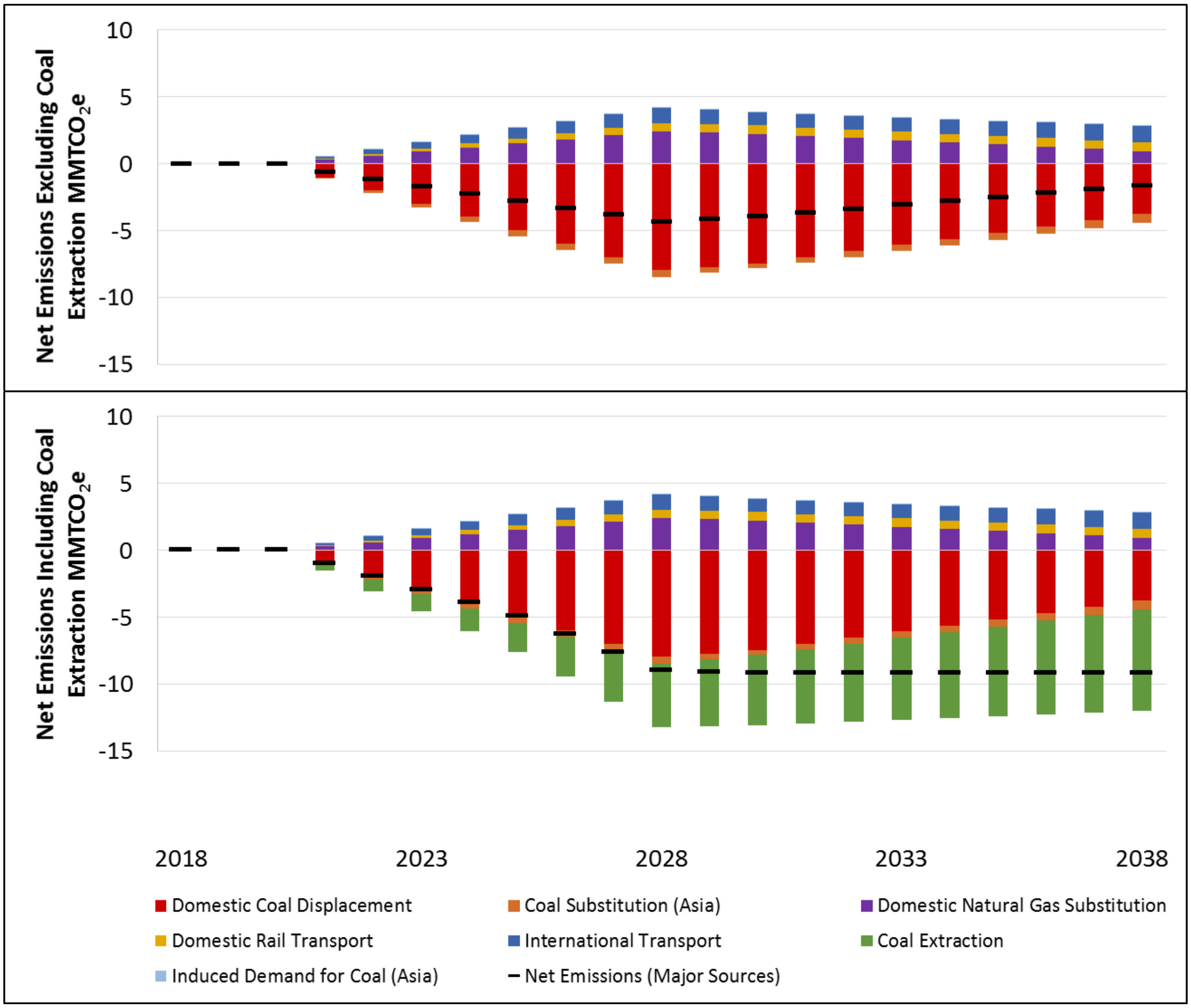
Note: Net GHG emissions represent the difference between the Proposed Action and the no-action.

3.1.15.3 Lower Bound Scenario

In the Lower Bound scenario (Figure 14), coal displacement in the United States results in a reduction of GHG emissions. The displacement of U.S. coal is highest in the Lower Bound Scenario because the PRB and Uinta Basin coal supply curves are assumed higher than the base assumption coal curves, which results in higher coal prices in both the No Action and Proposed Action alternatives. Thus the domestic coal demand is more sensitive to the coal price increase that occurs in the Proposed Action (i.e., for a percent increase in price, coal demand would decrease by 1.6 million metric tons on average). Induced demand in Asia increases Asian coal GHG emissions. In the Lower Bound Scenario, there is a decrease in emissions due to the mix of coal consumed in Asia as more coal with a lower carbon emissions rate is consumed and less coal with a higher carbon emissions rate is consumed. Thus the overall net emissions in Asia are less than in the 2015 U.S. and International Energy Policy Scenario. Compared to the No Clean Power Plan scenario, the Lower Bound Scenario results in higher natural gas emissions in the United States due to the deeper reduction of coal use domestically and the replacement of some of that coal energy with natural gas. In summary, the Lower Bound scenario results in the following emissions conditions.

- Overall net emissions are lower than in the No Clean Power Plan scenario.
- Coal emissions in Asia would be lower than in the No Clean Power Plan scenario because of the mix of coals consumed.
- Natural gas substitution is higher because domestic coal prices are more sensitive to changes in demand in the Lower Bound than the No Clean Power Plan scenario.
- Coal extraction emissions are lower than in the No Clean Power Plan scenario, driven by coal production reductions in Russia and China.

Figure 14. Lower Bound – Net Annual Emissions Excluding and Including Coal Extraction, 2018–2038



Note: Net GHG emissions represent the difference between the Proposed Action and the no-action.

3.1.15.4 Upper Bound Scenario

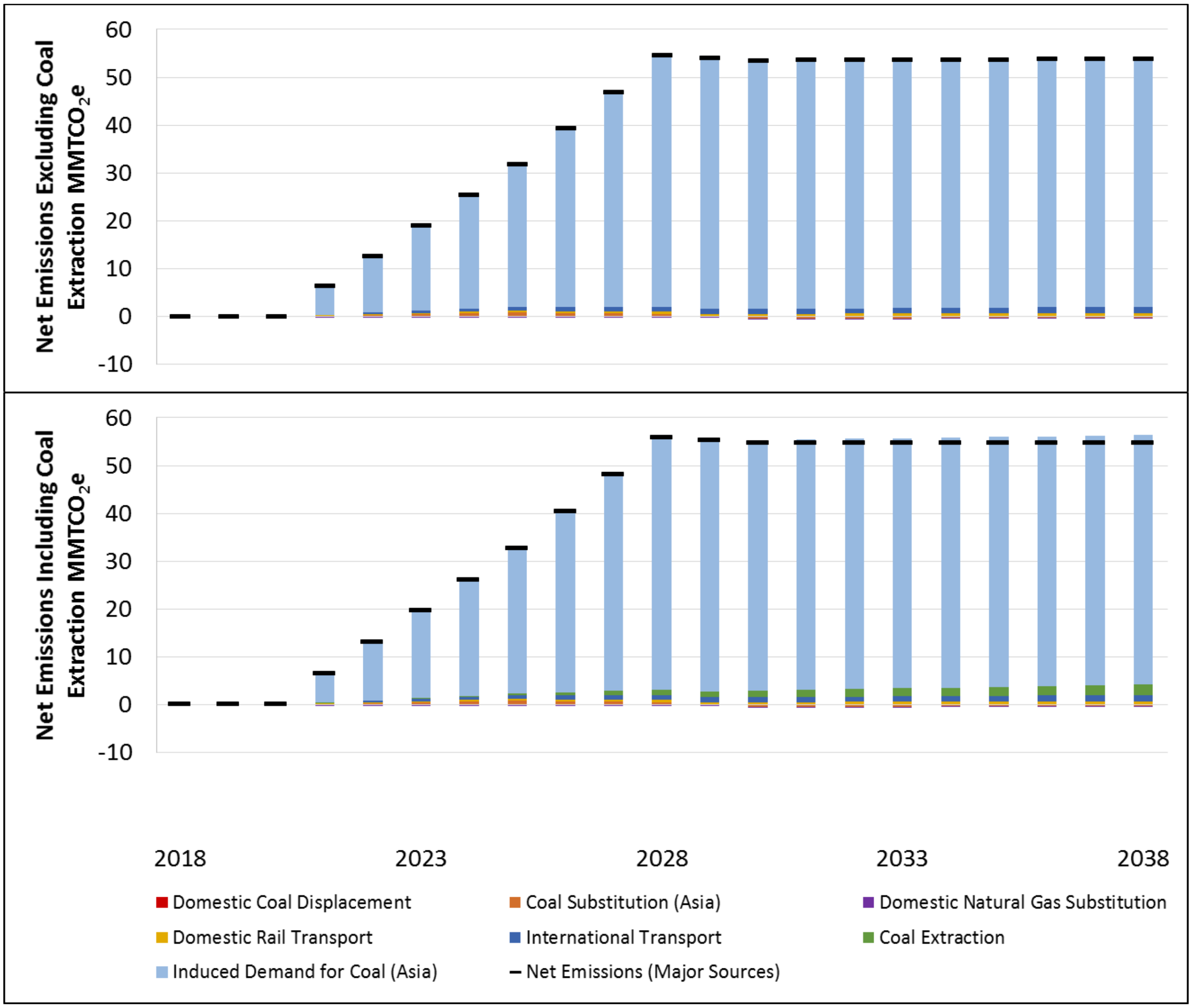
The Upper Bound scenario (Figure 15), which has a higher sensitivity to coal price changes, exhibits stronger induced demand from Asia, resulting in higher Asian coal emissions than the No Clean Power Plan scenario. There is a higher sensitivity to coal price changes due to the overall higher global coal demand, which in turn stresses the coal supply chain more than the other scenarios.[39] In summary, the Upper Bound scenario results in the following emissions conditions.

- Overall net emissions are higher than in the No Clean Power Plan scenario.
- Coal emissions in Asia rise more than in the No Clean Power Plan scenario because more demand is induced in the Upper Bound Scenario than in the No Clean Power Plan Scenario.

[39] The Upper Bound Scenario international coal demand is 33% higher than the No Clean Power Plan Scenario and 71% higher than the Lower Bound and 2015 U.S. and International Energy Policy Scenarios demand in 2040.

- Coal extraction emissions are higher than in the No Clean Power Plan scenario, driven by coal production increases in the Powder River and Uinta Basins, and China.

Figure 15. Upper Bound – Net Annual Emissions Excluding and Including Coal Extraction, 2018–2038



Note: Net GHG emissions represent the difference between the Proposed Action and the no-action.

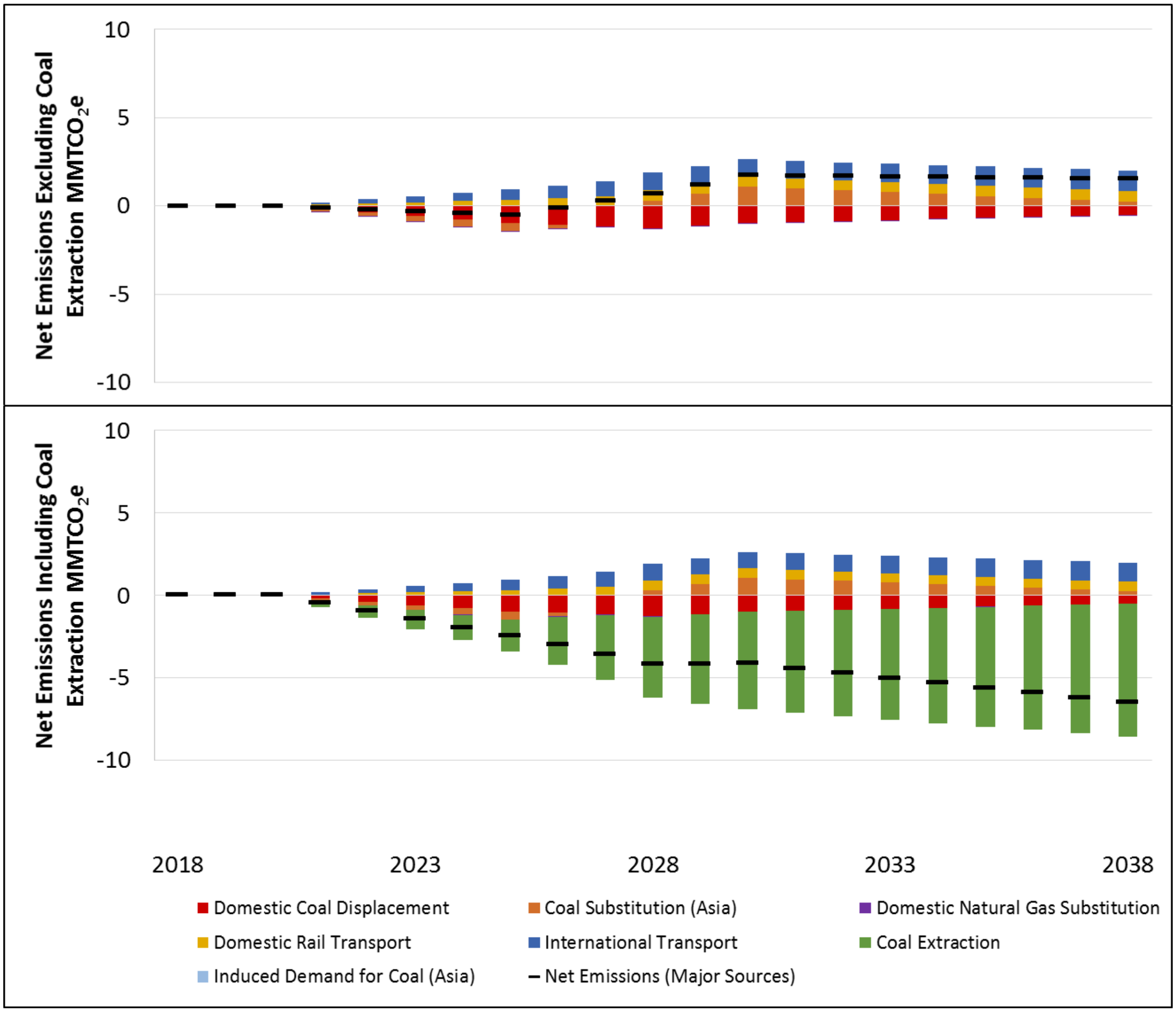
3.1.15.5 2015 U.S. and International Energy Policy Scenario

The 2015 U.S. and International Energy Policy scenario (Figure 16) has U.S. coal displacement that is lower than the No Clean Power Plan Scenario and higher than the Lower Bound scenario. This shift in coal displacement occurs because the climate policy in the United States depresses coal demand and prices and reduces coal combustion. Therefore, in this scenario, domestic coal emissions and natural gas emissions stay relatively flat throughout the analysis period. Net emissions in Asia are lower than in the No Clean Power Plan scenario and are driven by the change in the mix of coals. (One important note is that, although state climate emissions goals drive up the use of renewables relative to the No Clean Power Plan scenario, use of coal is permissible). Natural gas substitution is low in the 2015 U.S. and International Energy Policy Scenario because the Proposed Action does not cause coal prices to increase enough to result in a large decrease in coal consumption.

- The decrease in net emissions[40] from domestic coal combustion is greater than in the No Clean Power Plan scenario because coal consumption in the 2015 U.S. and International Energy Policy scenario is more sensitive to changes in coal prices due to lower overall electric demand (the coal elasticity of demand results in a decrease in coal demand of 0.5 million metric tons for every 1% increase in price).
- Net emissions from coal combustion in Asia increase less than in the No Clean Power Plan scenario because of changes in the mix of coal consumed.
- Net GHG emissions in Asia from coal combustion in the 2015 U.S. and International Energy Policy scenario are driven by changes in coal types consumed (i.e., low CO_2-content versus high CO_2-content coal).
- Net emissions from domestic natural gas combustion are greater than in the No Clean Power Plan scenario because of the larger decrease in domestic coal consumption in the 2015 U.S. and International Energy Policy scenario.
- Net emissions in coal extraction are lower than in the No Clean Power Plan scenario, driven by coal production reductions in Russia and China.

[40] Net GHG emissions represent the difference between the Proposed Action and the No-Action.

Figure 16. 2015 U.S. and International Energy Policy—Net Annual Emissions Excluding and Including Coal Extraction, 2018–2038



Note: Net GHG emissions represent the difference between the Proposed Action and the no-action.

To highlight the differences between net emissions during construction, net emissions during initial operation of the terminal, and net emissions during full operation of the terminal, Table 68 presents total net emissions for each phase as well as average net emissions if coal extraction is excluded. Table 69 shows net emissions if coal extraction is included.

Table 68. Net Emissions (Direct and Indirect) Excluding Coal Extraction by Phase ($MMTCO_2e$)

Phase	Years	2015 Energy Policy GHG Emissions	2015 Energy Policy Avg. Annual Emissions	Lower Bound GHG Emissions	Lower Bound Avg. Annual Emissions	Upper Bound GHG Emissions	Upper Bound Avg. Annual Emissions	No Clean Power Plan GHG Emissions	No Clean Power Plan Avg. Annual Emissions
Net Emissions Excluding Coal Extraction ($MMTCO_2e$)									
Construction Emissions	2018–2020	0.21	0.07	0.21	0.07	0.21	0.07	0.21	0.07
Total Net Emissions for Initial Operation	2021–2027	0.30	0.04	-13.66	-1.95	183.41	26.20	14.19	2.03
Total Net Emissions for Full Operations	2028–2038	21.85	1.99	-27.86	-2.53	596.80	54.25	37.35	3.40
Total Emissions	2018–2038	22.36		-41.31		780.42		51.75	

Table 69. Net Emissions (Direct and Indirect) Including Coal Extraction by Phase ($MMTCO_2e$)

		2015 Energy Policy		Lower Bound		Upper Bound		No Clean Power Plan	
Phase	Years	GHG Emissions	Avg. Annual Emissions	GHG Emissions	Avg. Annual Emissions	GHG Emissions	Avg. Annual Emissions	GHG Emissions	Avg. Annual Emissions
Net Emissions Including Coal Extraction ($MMTCO_2e$)									
Construction Emissions	2018–2020	0.21	0.07	0.21	0.07	0.21	0.07	0.21	0.07
Total Net Emissions for Initial Operation	2021–2027	-12.37	-1.77	-26.92	-3.85	186.11	26.59	8.04	1.15
Total Net Emissions for Full Operations	2028–2038	-51.38	-4.67	-95.34	-8.67	615.17	55.92	-13.00	-1.18
Total Emissions	2018–2038	-63.54		-122.04		801.49		-4.75	

3.1.15.6 Cumulative Scenario

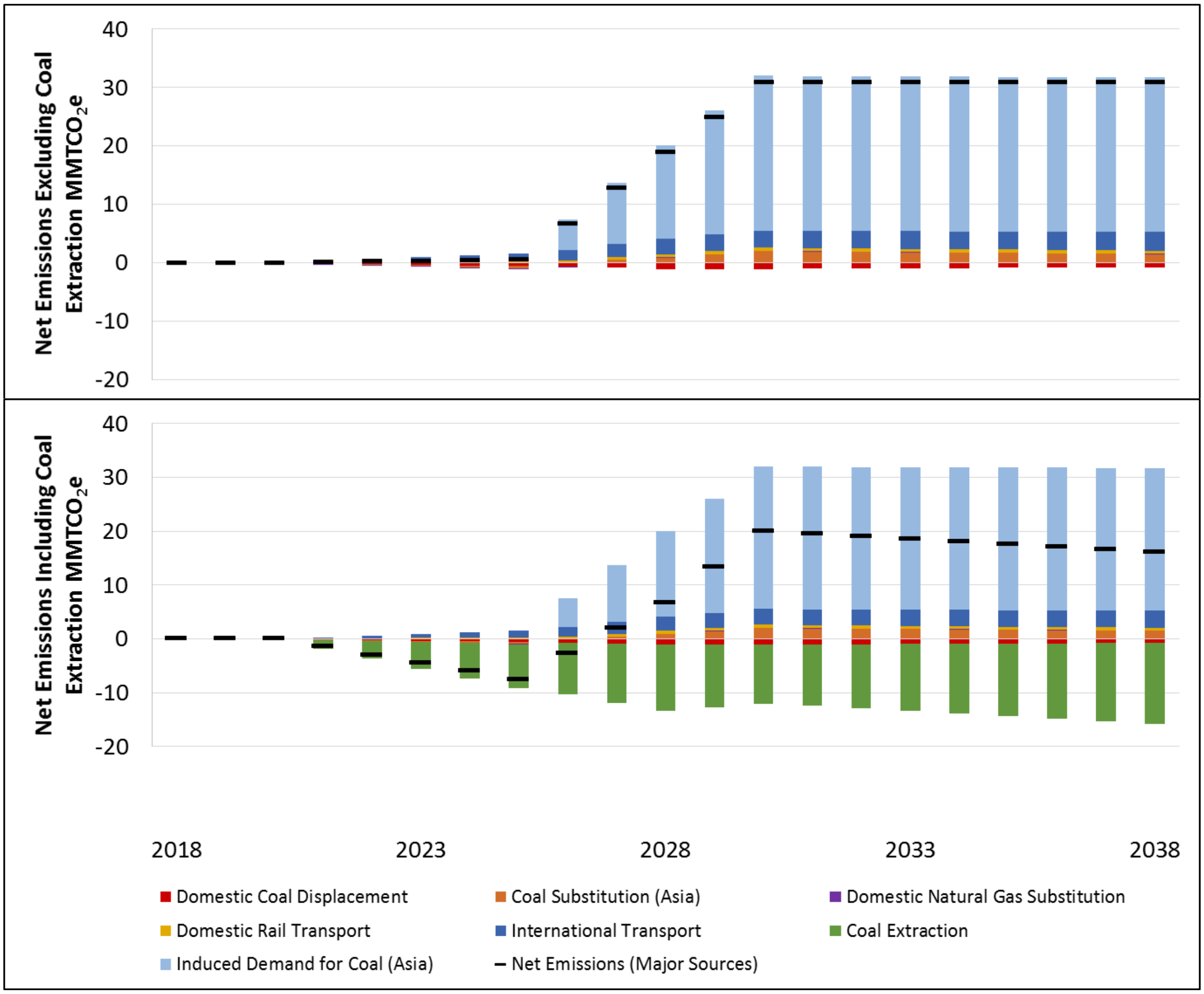
The Cumulative scenario includes other planned export coal terminals in the Pacific Northwest. Each terminal would operate at full capacity, except for the Ridley terminal due to its long distance from the Powder River Basin, for a total export tonnage of 175 million metric tons, which includes both thermal and metallurgical coal.[41] The emissions from the operation of the other coal export terminals are not included in the cumulative emissions analysis. Their impact is solely limited to their ability to influence coal supplies and prices. All other assumptions are the same as the No Clean Power Plan scenario. The Cumulative scenario compares the no-action without the additional coal export terminals against the Proposed Action that includes the other coal export terminals.

The Cumulative scenario emissions are dominated by changes in Asian coal emissions (Figure 17.). The operation of multiple coal export terminals changes the mix of coal types consumed in Asia with only a small decline in domestic coal consumption. The additional export capacity beyond the Proposed Action causes a decrease in coal prices in 2030, which results in induced demand equivalent to about 12.5 million metric tons. In summary, the Cumulative scenario results in the following emissions conditions.

- Net emissions relative to the no-action are higher than the No Clean Power Plan scenario (351.24 $MMTCO_2e$ versus -51.75 from 2018 through 2038 excluding coal extraction, and 165.43 $MMTCO_2e$ versus -4.75 from 2018 through 2038 including coal extraction).
- The change in Asian coal combustion emissions is due to a mix of induced demand and a change in the mix of coals consumed.
- Coal use in the United States declines more relative to the No Clean Power Plan scenario due to the increased demand from multiple coal export terminals that is a greater stimulus to the domestic supply system and, as such, causes coal prices to rise higher and coal demand to fall farther. The change in coal use in the United States is less than 0.9 million metric tons in both the Cumulative and No Clean Power Plan Scenarios.
- Natural gas substitution follows the same pattern as in the No Clean Power Plan scenario as natural gas consumption moves in the opposite direction of coal consumption changes in each scenario.
- Coal extraction emissions show a similar trend as the No Clean Power Plan scenario; however, emissions are almost exclusively driven by a reduction in coal production in China.

[41] The analysis for the EIS only models thermal coal as only thermal coal would be exported through the proposed terminal. The total export capacity for thermal coal is 157 million metric tons.

Figure 17. Cumulative Scenario—Net Annual Emissions, 2018–2038



Note: Net GHG emissions represent the difference between the Proposed Action and the no-action.

3.2 No-Action Alternative

Under the No-Action Alternative, the Applicant would not construct the coal export terminal and GHG emissions would not be affected by construction or operation. However, the Applicant has indicated that the operation of the current bulk product terminal would continue and increase within the project area. The Applicant would not construct Docks 2 and 3. Dock 1 would continue to be used for bulk cargo, primarily alumina, and might be used for general cargo.

Alternative uses of the project area would be expected to result in minimal increases in GHG emissions relative to current conditions in Cowlitz County. Under the No-Action Alternative, the Applicant anticipates importing from Asia up to 600,000 short tons of calcined pet coke a year. This material would arrive by vessel and be stored in a building at the facility. Approximately 200,000 short tons of coal tar pitch per year could also be imported by vessel, as well as an undetermined amount of cement. Future operations would result in two additional daily trains arriving and departing the facility with an average rail car length of 30 cars carrying bulk product. Each train is composed of two locomotives. In addition, an average of 26 Panamax-sized vessels would arrive and depart each year, an increase of 20 vessels compared to the 6 vessels that currently arrive and depart. Truck haul emissions associated with the transport of coal to the nearby Weyerhaeuser facility would increase and are included in estimate of GHG emissions. Emissions from the consumption of electricity at the bulk product terminal would increase due to the planned terminal expansion; however, the extent of this increase is uncertain. The estimated emissions are shown in Table 70.

Table 70. No-Action Alternative Annual Average Emissions from Rail, Vessel, and Haul Trucks Operating within Cowlitz County ($MMTCO_2e$)

Source	Maximum Annual Average Emissions ($MMTCO_2e$)
Locomotive combustion	0.0005
Vessel combustion	0.0004
Haul trucks	0.0002
Total	**0.0012**

$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

The no-action in coal market assessment contains different boundaries than the emission sources above (i.e., the coal market assessment examines effects on the international coal market, while the No-Action Alternative examines alternative uses of the project area). While the no-action for the coal market assessment examines the implications of not building the coal export terminal, net emissions between a given coal market scenario and the no-action consider changes in emissions from coal combustion in Asia and the U.S. for instance, but do not consider changes in emissions from emission sources described in Table 70. In particular, the no-action as it relates to the coal market assessment does not evaluate net impacts associated with existing vessel, rail, and vehicle traffic.

Chapter 4
Supplementary Data

4.1 Interpolated Results from Coal Market Assessment

The GHG analysis used coal market assessment estimates on changes in domestic and international coal demand for 2025, 2030, and 2040. For the GHG analysis, the years 2025, 2028, and 2038 are extracted from the full, interpolated time series and presented below. As mentioned in Section 2.2.2.2, *Method for Assembling an Emissions Time Series,* the coal market assessment values were adjusted to capture the gradual increase in coal exports from 2020 to 2025 (from zero to 25 million metric tons) and 2028 (full capacity of 44 million metric tons). This chapter presents the interpolated results based on the coal market assessment results. The following tables are presented.

- Table 71. Interpolated Coal Market Assessment Results, 2015 U.S. and International Energy Policy
- Table 72. Interpolated Coal Market Assessment Results, Lower Bound
- Table 73. Interpolated Coal Market Assessment Results, Upper Bound
- Table 74. Interpolated Coal Market Assessment Results, No Clean Power Plan
- Table 75. Interpolated Coal Market Assessment Results, Cumulative

In addition, Table 76 provides the net change in coal extraction volumes for the year 2028 and the entire 2018 through 2038 analysis period.

Table 71. Interpolated Coal Market Assessment Results, 2015 U.S. and International Energy Policy

	2025	2028	2038
Coal Exported Through the Proposed Action (million metric tons)	**25.0**	**44.0**	**44.0**
Coal by Origin exported Through the Proposed Action (million metric tons)			
Powder River Basin - Total	25.0	44.0	37.5
MT Powder River Basin	9.9	29.0	36.1
MT Signal Peak	0.0	0.0	0.0
Powder River Basin WY 8400	0.0	0.0	0.0
Powder River Basin WY 8800	15.1	15.0	1.4
Uinta Basin - Total	0.0	0.0	6.5
Colorado	0.0	0.0	3.2
Utah	0.0	0.0	3.3
Total U.S. CO_2 Emissions - Coal (thousand metric tons)	**-953.2**	**-1,251.4**	**-498.8**
Total Asian CO_2 Emissions - Coal (thousand metric tons)	**-482.5**	**317.1**	**252.9**
Asia - Other	-1,179.9	-830.7	0.0
Australia	0.0	0.0	0.0
China	-66.8	1.6	16.2
Hong Kong	472.4	416.5	149.0
India	0.0	0.0	0.0
Indonesia	0.0	0.0	0.0
Japan	-95.1	-165.9	35.7
Korea	-151.8	-6.3	118.5
Taiwan	538.8	901.8	-66.5
Total U.S. Natural Gas Consumption (TBtu)	**0.0**	**1.2**	**0.8**
Total U.S. CO_2 emissions - Natural Gas (thousand metric tons)	**0.0**	**65.2**	**41.6**
Net Change in Shipping GHG Emissions from all Asian Sources, Excluding Transport from coal export terminal to WA State Border – Thousand $MTCO_2e$	**602.6**	**1,013.2**	**1,179.9**

Table 72. Interpolated Coal Market Assessment Results, Lower Bound

	2025	2028	2038
Coal Exported Through the Proposed Action (million metric tons)	**25.0**	**44.0**	**44.0**
Coal by Origin exported Through the Proposed Action (million metric tons)			
Powder River Basin - Total	25.0	44.0	44.0
MT Powder River Basin	0.0	0.0	0.0
MT Signal Peak	0.0	0.0	0.0
Powder River Basin WY 8400	0.0	0.0	11.4
Powder River Basin WY 8800	25.0	44.0	32.6
Uinta Basin - Total	0.0	0.0	0.0
Colorado	0.0	0.0	0.0
Utah	0.0	0.0	0.0
Total U.S. CO_2 Emissions - Coal (thousand metric tons)	**-4,928.4**	**-7,940.6**	**-3,725.4**
Total Asian CO_2 Emissions - Coal (thousand metric tons)	**-473.8**	**-535.5**	**-652.1**
Asia - Other	-161.2	-113.5	0.0
Australia	0.0	0.0	0.0
China	-52.4	-89.8	-122.2
Hong Kong	269.2	45.4	-256.0
India	-632.9	-445.5	0.0
Indonesia	0.0	0.0	0.0
Japan	-95.1	-165.9	-41.6
Korea	-151.8	-252.2	-59.1
Taiwan	350.4	486.1	-173.3
Total U.S. Natural Gas Consumption (TBtu)	**28.8**	**45.6**	**18.3**
Total U.S. CO_2 emissions - Natural Gas (thousand metric tons)	**1,531.1**	**2,424.0**	**972.4**
Net Change in Shipping GHG Emissions from all Asian Sources, Excluding Transport from coal export terminal to WA State Border – Thousand $MTCO_2e$	**769.8**	**1,130.8**	**1,189.9**

Table 73. Interpolated Coal Market Assessment Results, Upper Bound

	2025	2028	2038
Coal Exported Through the Proposed Action (million metric tons)	**25.0**	**44.0**	**44.0**
Coal by Origin exported Through the Proposed Action (million metric tons)			
Powder River Basin - Total	25.0	42.4	32.1
MT Powder River Basin	25.0	42.4	32.1
MT Signal Peak	0.0	0.0	0.0
Powder River Basin WY 8400	0.0	0.0	0.0
Powder River Basin WY 8800	0.0	0.0	0.0
Uinta Basin - Total	0.0	1.6	11.9
Colorado	0.0	0.0	2.9
Utah	0.0	1.6	9.0
Total U.S. CO_2 Emissions - Coal (thousand metric tons)	**17.4**	**26.0**	**115.3**
Total Asian CO_2 Emissions - Coal (thousand metric tons)	**30,790.8**	**52,895.8**	**51,805.7**
Asia - Other	0.0	-440.4	-160.0
Australia	0.0	0.0	0.0
China	28,225.5	49,371.7	49,168.2
Hong Kong	23.4	149.7	278.0
India	1,429.7	2,289.3	1,525.4
Indonesia	0.0	0.0	0.0
Japan	477.4	618.8	350.6
Korea	130.9	292.4	251.1
Taiwan	503.9	614.3	392.4
Total U.S. Natural Gas Consumption (TBtu)	**-0.4**	**-0.5**	**-0.1**
Total U.S. CO_2 emissions - Natural Gas (thousand metric tons)	**-18.9**	**-24.1**	**-3.6**
Net Change in Shipping GHG Emissions from all Asian Sources, Excluding Transport from coal export terminal to WA State Border – Thousand $MTCO_2e$	**739.3**	**1,116.7**	**1,366.4**

Table 74. Interpolated Coal Market Assessment Results, No Clean Power Plan

	2025	2028	2038
Coal Exported Through the Proposed Action (million metric tons)	**25.0**	**44.0**	**44.0**
Coal by Origin exported Through the Proposed Action (million metric tons)			
Powder River Basin - Total	25.0	44.0	44.0
MT Powder River Basin	25.0	44.0	44.0
MT Signal Peak	0.0	0.0	0.0
Powder River Basin WY 8400	0.0	0.0	0.0
Powder River Basin WY 8800	0.0	0.0	0.0
Uinta Basin - Total	0.0	0.0	0.0
Colorado	0.0	0.0	0.0
Utah	0.0	0.0	0.0
Total U.S. CO_2 Emissions - Coal (thousand metric tons)	**-2.6**	**-2.1**	**-4.0**
Total Asian CO_2 Emissions - Coal (thousand metric tons)	**1,579.4**	**1,835.5**	**1558.8**
Asia - Other	0.0	-672.2	-224.1
Australia	0.0	0.0	0.0
China	183.3	300.0	57.0
Hong Kong	522.6	979.5	356.1
India	-357.0	-251.3	0.0
Indonesia	0.0	0.0	0.0
Japan	710.1	499.9	102.9
Korea	0.0	0.0	92.5
Taiwan	520.5	979.5	1,174.4
Total U.S. Natural Gas Consumption (TBtu)	**0.0**	**0.0**	**0.0**
Total U.S. CO_2 emissions - Natural Gas (thousand metric tons)	**0.8**	**0.2**	**-0.1**
Net Change in Shipping GHG Emissions from all Asian Sources, Excluding Transport from coal export terminal to WA State Border – Thousand $MTCO_2e$	**458.0**	**927.2**	**918.5**

Table 75. Interpolated Coal Market Assessment Results, Cumulative

	2025	2028	2038
Coal Exported Through the Proposed Action (million metric tons)	**25.0**	**44.0**	**44.0**
Coal by Origin exported Through the Proposed Action (million metric tons)			
Powder River Basin - Total	25.0	44.0	44.0
MT Powder River Basin	25.0	44.0	44.0
MT Signal Peak	0.0	0.0	0.0
Powder River Basin WY 8400	0.0	0.0	0.0
Powder River Basin WY 8800	0.0	0.0	0.0
Uinta Basin - Total	0.0	0.0	0.0
Colorado	0.0	0.0	0.0
Utah	0.0	0.0	0.0
Total U.S. CO_2 Emissions - Coal (thousand metric tons)	**-556.0**	**-1,028.3**	**-734.3**
Total Asian CO_2 Emissions - Coal (thousand metric tons)	**-394.0**	**16,801.8**	**27,986.3**
Asia - Other	0.0	-678.4	-300.7
Australia	0.0	0.0	0.0
China	247.9	16,306.7	26,876.6
Hong Kong	522.6	953.6	-163.6
India	-357.0	-251.3	0.0
Indonesia	0.0	0.0	0.0
Japan	-1,327.9	-796.7	230.3
Korea	0.0	89.3	148.8
Taiwan	520.5	1,178.7	1,194.9
Total U.S. Natural Gas Consumption (TBtu)	**-0.4**	**0.8**	**0.4**
Total U.S. CO_2 emissions - Natural Gas (thousand metric tons)	**-23.7**	**43.1**	**20.2**
Net Change in Shipping GHG Emissions from all Asian Sources, Excluding Transport from coal export terminal to WA State Border – Thousand $MTCO_2e$	**1,302.6**	**2,666.8**	**3,194.4**

Table 76. Coal Extraction by Region (Million Metric Tons)

Extraction Source / Period	Scenario: 2015 Energy Policy	Lower Bound	Upper Bound	No Clean Power Plan	Cumulative
Powder River Basin					
Annual Extraction, 2028	43.46	36.09	40.07	44.00	83.08
Total Extraction, 2018-2038	582.64	524.93	522.80	628.00	1,309.33
Uinta Basin					
Annual Extraction, 2028	-0.24	0.09	1.15	<0.005	-0.03
Total Extraction, 2018-2038	21.10	3.98	56.15	<0.005	-0.22
Other U.S. Coals					
Annual Extraction, 2028	0.45	2.26	<0.005	<0.005	1.37
Total Extraction, 2018-2038	14.92	26.47	10.22	-0.01	19.04
Australia					
Annual Extraction, 2028	-6.15	-6.19	0.00	-19.09	-0.44
Total Extraction, 2018-2038	-75.80	-76.39	0.00	-238.25	-58.72
Canada					
Annual Extraction, 2028	0.00	-0.02	0.00	0.00	0.00
Total Extraction, 2018-2038	0.00	-0.22	0.00	0.00	0.00
China					
Annual Extraction, 2028	-8.36	-7.09	6.11	-8.96	-48.25
Total Extraction, 2018-2038	-226.57	-197.99	75.40	-146.45	-721.00
India					
Annual Extraction, 2028	0.00	-7.59	0.00	-4.28	-4.28
Total Extraction, 2018-2038	0.00	-62.12	-70.45	-35.04	-35.04
Indonesia					
Annual Extraction, 2028	-8.29	-1.13	-12.32	-8.01	-14.44
Total Extraction, 2018-2038	-67.83	-9.27	-135.61	-94.96	-209.24
Russia					
Annual Extraction, 2028	-16.08	-15.72	-8.45	0.00	0.01
Total Extraction, 2018-2038	-170.44	-167.01	-104.25	-48.86	0.17
South Africa					
Annual Extraction, 2028	0.18	0.00	-2.04	<0.005	0.00
Total Extraction, 2018-2038	1.49	0.00	-25.15	<0.005	-0.05
Net Extraction					
Annual Extraction, 2028	4.78	0.67	26.57	3.65	17.01
Total Extraction, 2018-2038	78.03	42.38	354.27	64.43	304.33

Chapter 5
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